THE ENVIRONMENTAL IMPLICATIONS
OF HYDROGEN FUEL SYSTEMS

Prepared for Environment Canada

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ABSTRACT

This study assesses the environmental implications of hydrogen fuel systems. Technologies which must be available to support hydrogen utilization are reviewed, current market demand as an industrial feedstock and as a fuel are established and forecast to the year 2025. Representative hydrogen fuel systems are proposed and the environmental and safety implications of each component and the fuel system are established.

Current hydrogen demand is estimated to be 15.50 billion m^3 and is consumed almost exclusively as an industrial feedstock. In the year 2025, hydrogen demand is forecast to increase to 37.18 billion m^3 of which 98.5 percent will be required by industrial markets and 1.5 percent by a small but growing fuels market.

The component production, transportation/distribution, storage and end use technologies for each of seven generic hydrogen fuel markets are established and materials and energy balances estimated. Overall, the results indicate the environmental implications of electrolytic hydrogen fuel systems are relatively benign. Production and end use emissions are substantially improved relative to conventional fuels, although increased NO_x end use emissions and co-product oxygen emissions from production may be problematic. An evaluation of the environmental impacts of producing electricity for use in electrolysis facilities is recommended. The environmental benefits of electrolytic hydrogen fuel use may be offset to some degree by the environmental impacts of producing electricity. Present day assessments of environmental effects of hydrogen fuel systems are constrained by the lack of good process data, as most technologies are still at a very early stage of development.

FOREWORD

Several recent studies have focused attention on hydrogen as an energy medium. The report of the federal Parliamentary Task Force on Alternative Energy and Oil Substitution advocated the development of energy systems based on hydrogen. An investigation of hydrogen energy opportunities for Ontario concluded that electrolytic hydrogen could play a significant role in displacing natural gas imported into Ontario and measurably reduce dependence on crude oil products in the transportation sector.

The hydrogen fuel cycle is generally expected to be more environmentally benign than existing energy systems. Nonetheless, there may be specific environmental concerns with the production, transportation, storage and utilization of hydrogen. Although many of the technologies required to support the hydrogen fuel cycle are still under development, it is appropriate to develop an early appreciation of their potential environmental implications, both individually and collectively as an energy system. As a result, environmentally appropriate technologies and practices may be identified and encouraged, in concert with technology development activities. An early appreciation of environmental implications will allow Environment Canada to take a pro-active position, as hydrogen fuel systems emerge.

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1. SUMMARY AND CONCLUSIONS

Hydrogen is currently an important chemical feedstock to several Canadian industries. It has a potential for numerous applications as a fuel and may ultimately serve as a replacement for natural gas or petroleum by storing and delivering energy derived from non-fossil sources. In this latter case, hydrogen is an energy carrier, similar to electricity, rather than a primary energy source.

Current annual consumption of hydrogen is estimated to be 15.55 billion m^3. Most is produced and consumed on-site by the methanol, ammonia and petroleum refining industries. Bitumen upgrading as required for the two tar sands plants in Alberta also consumes hydrogen. The commercially standard practice in producing hydrogen is to steam reform natural gas. Numerous other industries also use hydrogen in smaller quantities, either as a feedstock or because its physical and chemical characteristics improve the effectiveness of a particular process. Aside from its use in specialty markets such as brazing and welding, hydrogen is not currently used as fuel in Canada.

Future demand for hydrogen will be influenced by a host of technical and economic factors. It is likely that hydrogen as used for industrial purposes will continue to predominate well into the next century. New requirements for ore reduction, different crude oil refining requirements, increased reliance on bitumen and coal liquids and growth in methanol and ammonia demand will contribute to at least a doubling in hydrogen demand by the year 2025. Most of this increased demand is likely to be met by increased natural gas steam reforming capacities. A small but growing hydrogen fuels market is forecast for the year 2025. By that year, in the order of 580 million m^3 of hydrogen is projected for fuel applications, compared to 36.6 billion m^3 in industrial feedstock markets. Non-fossil derived hydrogen is the likely source for hydrogen fuel purposes.

In contrast to the industrial feedstock market which typically produces and consumes hydrogen on site, hydrogen fuel markets will require new production technologies, bulk and small scale storage, a transmission/distribution infrastructure and new end use technologies. Depending on its application, hydrogen may be required either as a gas or as a liquid. Each has its own technical requirements and each fuel application will differ in its specifics. In most cases, the technologies required to support hydrogen fuel systems are at a very early stage of development. The current lack of technical readiness, in combination with uncertain hydrogen fuel system economics, are the primary reasons for the low penetration of hydrogen fuel, forecast for the year 2025.

The environmental implications of new hydrogen fuel systems are relatively minor. Although the technologies required for these systems remain for the most part undeveloped, their potential environmental effects can be broadly defined. Feasible component technologies for the production, distribution, storage and utilization of hydrogen are matched against the fuel system requirements for utility applications and in the transportation, residential, commercial and industrial sectors.

The hydrogen component technologies reviewed are:

- production: steam reforming natural gas and solid polymer electrolysis
- liquefaction
- bulk storage: as a compressed gas, a cryogenic liquid or in metal hydrides
- transmission and distribution: as a cryogenic liquid by pipeline, truck or rail and as a gas by pipeline
- small scale storage: as a gas or as a liquid
- utilization: in fuel cells, internal combustion engines or catalytic combustors

Depending on the nature of the fuel application, hydrogen will be required as a gas or as a liquid. As a result, each application will have somewhat different technical requirements. The fuel system is the sum of the appropriate component technologies as outlined above. Feasible hydrogen fuel applications are:

- air, rail and road vehicles utilizing liquid hydrogen
- supplementing natural gas with gaseous hydrogen
- replacing natural gas with gaseous hydrogen
- storing electricity via gaseous hydrogen and reconversion in fuel cells or gas turbines
- utilizing hydrogen as a universal fuel, as a gas or liquid; this is the sum of all other individual applications

In combination, the component technologies and their grouping into fuel applications represent a full range of feasible hydrogen fuel systems. Within the limitations of available information on developing technologies, material and energy balances for each component of the fuel system are defined.

From the point of production through to end use hydrogen fuels systems have some attractive environmental benefits. The production of electrolytic hydrogen is a relatively clean process compared to the processing requirements of the conventional petroleum fuels industry, for example. It is also environmentally more attractive than conventional hydrogen production technologies which rely on natural gas as a feedstock. The displacement of these technologies by electrolytic hydrogen will virtually eliminate CO_2, CO, particulates, hydrocarbon and sulphur emissions. At the point of use, hydrogen fuel emissions will also be significantly lower than any other fuel, with the exception of NO_x which will tend to be higher.

The number of process conversion steps involved with hydrogen results in an overall reduction in systems energy efficiency relative to current fuels.

To the extent that electrolytic hydrogen is based on abundant, inexpensive sources of electricity this loss in efficiency may not be significant compared to the efficiency imperatives of non-renewable and depleting energy sources such as fossil fuels.

Safety issues will be a concern over the transition period to hydrogen fuel utilization. The concern arises not so much from an inherently lower safety level for hydrogen but from the need to develop and enforce somewhat unfamiliar safety precautions, many of which will be extended to the general public. Liquefied hydrogen storage and distribution in particular requires close attention to strict standards and procedures due to the extreme conditions and technical preconditions to maintain the liquid product.

For the most part, industrial users of hydrogen have an enviable safety record. Hydrogen has been safely handled by industry for decades, both as a high temperature gas and as a cryogenic liquid. Numerous standards, codes and guidelines for the handling of hydrogen have been developed by trade and interest groups and professional bodies, both in Canada and abroad. Many of these codes have been adopted by regulatory bodies, others are strictly adhered to by industry as a matter of safety. Compliance with voluntary standards is facilitated by insurance companies whose premiums are based on a thorough environmental risk analysis. Industry is responsible for worker safety and is liable for damages in case of an accident. New hydrogen applications as a transportation fuel, for example, will require new end use standards to be developed before market penetration can proceed. Regulatory authorities and procedures are in place to ensure that new standards are developed and adopted.

Future Environment Canada initiatives in the hydrogen area should be guided by the potential market demands, the prospects of technical readiness and the potential for environmental effects. Three broad areas of investigation are proposed:

- Technology Monitoring: to the extent that most technical issues have not been resolved and process conditions are unknown, developments in these areas should be monitored. The lack of good process information hinders the assessment of potential environment effects at this time.

- Near-Term Electrolytic Hydrogen Market Assessment: electrolytic hydrogen may be priced competitively with steam reforming natural gas by the turn of the century. The large industrial feedstock markets would be a significant target market. Niche markets such as remote communities or construction sites may be attractive candidates for small scale electrolysis matched to low head hydro or wind power generating facilities replacing diesel as a power source for electricity and fuel.

- Macro-Environmental Issues: a full systems review of the environmental impacts associated with supplying electricity to the electrolysis plant is required. Environmental impacts in producing electricity may counteract the environmental benefits of utilizing electrolytic hydrogen. Other research activities include an assessment of regional implications of large scale release of co-product oxygen, the nature and disposal requirements for numerous catalysts used in hydrogen fuel technologies and the extent of potential environmental degradation caused by increased NO_x emissions.

2. HYDROGEN TECHNOLOGY OVERVIEW

The introduction of new sources of hydrogen into industrial process or fuel markets will rely on the availability of a range of technologies from the producer to the consumer. The "Hydrogen Energy System"[1] is illustrated in Figure 2.1. The system and the technologies required to support it are composed of:

- Production - using fossil, nuclear, solar or geothermal energy sources
- Transportation - by vehicle or pipeline
- Storage - using pressurized gas vessels, metal hydrides, cryogenic vessels or underground
- Distribution - by vehicle or pipeline
- End Use - to electric utilities, and to commercial, residential, industrial and transportation users

Depending on the required application and form of hydrogen (gaseous, liquid), different combinations of these major system elements and options within them will be required. Subsequent chapters will specify particular hydrogen systems for existing and potential hydrogen applications.

This chapter will survey the status of hydrogen production, transportation, distribution and storage technologies. End use applications are discussed in chapter 3.

2.1 PRODUCTION TECHNOLOGIES

Hydrogen is routinely produced to satisfy the feedstock demands of several industries, notably for oil refining and ammonia and methanol production. Commercially available technologies include steam reforming natural gas, partial oxidation of liquid hydrocarbons and electrolysis of water. Steam

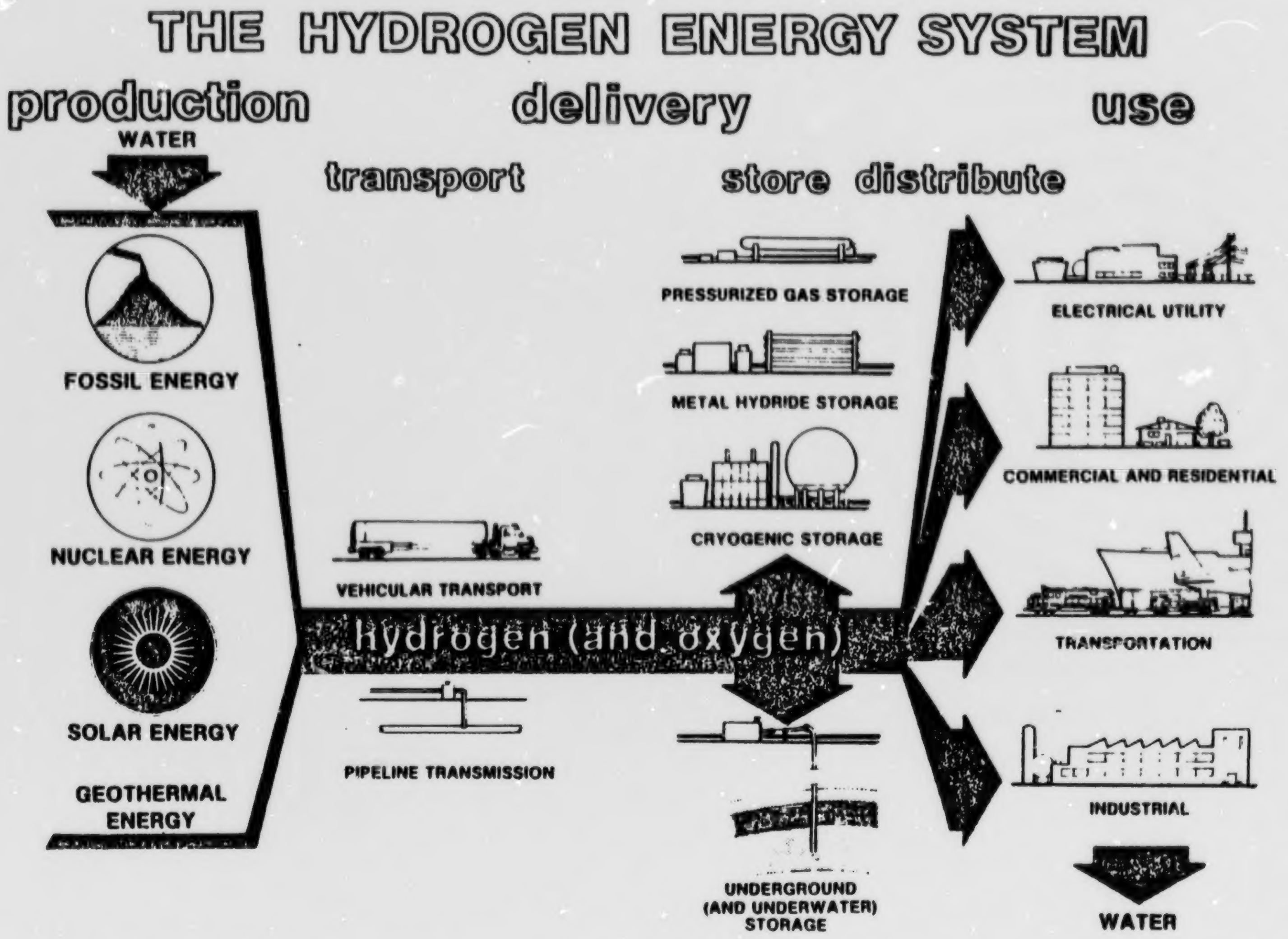

Figure 2.1 The "Hydrogen Energy System" Concept (1)

reforming is the primary production method at present. Numerous other technologies are under development but are not yet commercial. Most of these are at a very early stage of fundamental research and few have progressed to the large scale demonstration stage. This section will discuss the various technologies. The emphasis is placed on those which are commercial or show reasonable promise for eventual commercialization.

2.1.1 Steam Reforming of Natural Gas[6]

The primary step in the production of hydrogen from natural gas is the endothermal reaction of methane with steam at about 870°C on a nickel oxide catalyst. The overall process is illustrated in Figure 2.2. Natural gas is passed through a sulfur guard drum that contains zinc oxide to reduce sulfur compounds to a level of less than 5 ppm. Natural gas is then combined with superheated steam, forming the feed for the reforming furnace. Steam-to-methane ratios are usually 3 or 4:1 by volume.

The reformed gas is composed of hydrogen, water and carbon monoxide, plus some carbon dioxide and residual methane. This gas is cooled to about 370°C and passed through a shift reactor. Excess steam reacts with the carbon monoxide in a mildly exothermic reaction to form carbon dioxide and more hydrogen. The shifted gas stream is then compressed and the carbon dioxide removed.

Traces of carbon dioxide are removed by reacting the gas with hydrogen in the presence of a catalyst to form methane in a methanation process. Finally, the water is removed, leaving the hydrogen product (typically 97 percent pure). Further purification produces industrial gas (99.5 percent) or research grade (99.995 percent) hydrogen at an additional cost.

Steam reforming is a well-developed commercial process. It is the

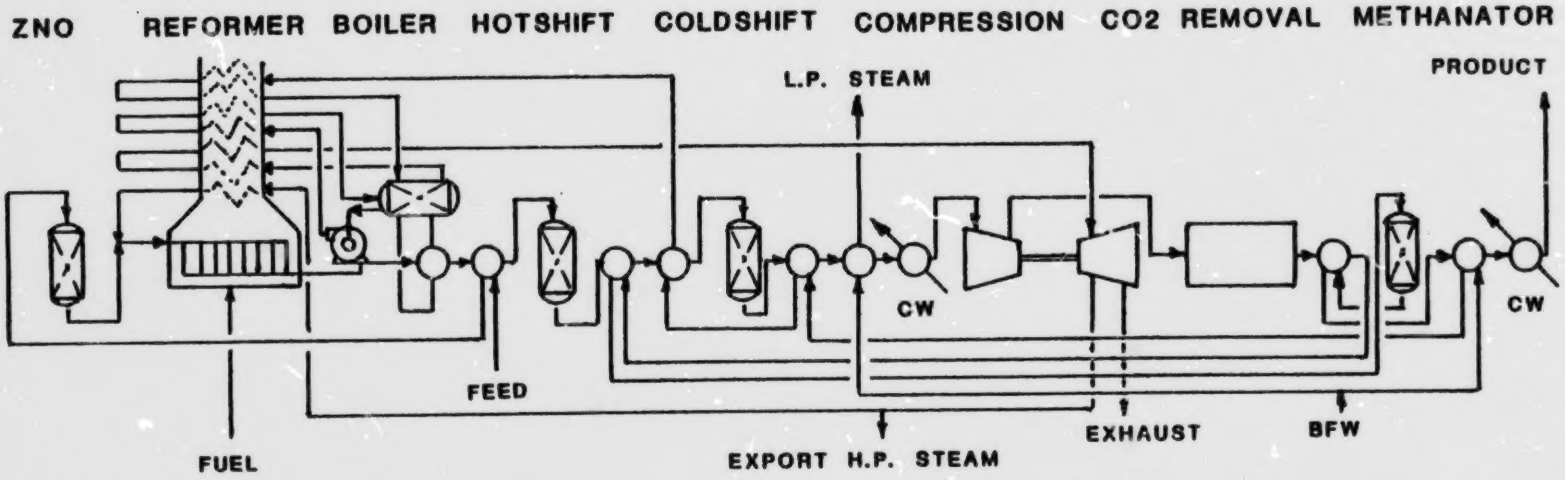

Figure 2.2 Simplified Process Flow Chart of a Natural Gas Steam Reforming System for the Production of Gaseous Hydrogen (7)

principal method of large-scale industrial hydrogen production. Ammonia and methanol production rely on this method to produce the large quantities of hydrogen required in their manufacture.

The disadvantages of this production process, from the standpoint of this study, is that this production process consumes fossil resources and produces carbon dioxide as a major byproduct.

The process economics of hydrogen production from natural gas vary greatly depending upon site location and the specific application of the hydrogen product. The future of pricing arrangements for natural gas feed to captive and merchant hydrogen producers will obviously be tied to the price of natural gas.

2.1.2 Partial Oxidation of Liquid Hydrocarbons[7]

A simplified process flow chart for the production of gaseous hydrogen by the partial oxidation of liquid hydrocarbons is shown in Figure 2.3. Two partial oxidation processes that have been extensively commercialized are: The Texaco Process (since 1954); and The Shell Gasification Process (since 1956). Gas consisting primarily of hydrogen and carbon monoxide is produced by burning hydrocarbons with high-purity oxygen or an oxygen-rich stream.

The Texaco Process, for example, injects high-purity oxygen (95 percent to 99 percent) into a gas generator, along with preheated steam and heavy oil. A typical steam-to-oil weight ratio would be 0.5:1. Resynthesis gas is treated in ways similar to the steam-natural gas reforming process, to increase the amount and the purity of the hydrogen. Hydrogen sulphide is removed and the stream is steam shifted, in a carbon monoxide conversion step, to produce more hydrogen. Carbon dioxide is removed from the hydrogen by an absorption process.

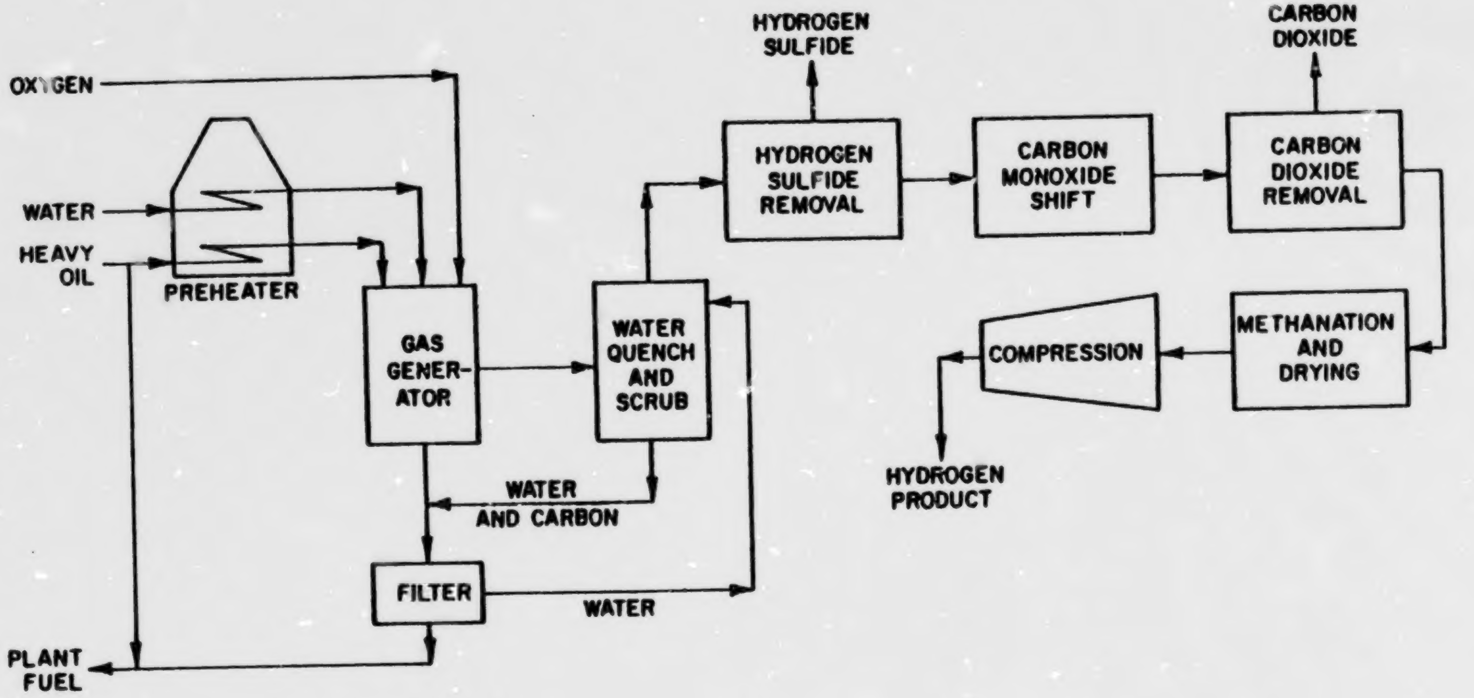

Figure 2.3 Simplified Process Flow Chart for the Production of Gaseous Hydrogen by the Partial Oxidation of Liquid Hydrocarbons

Hydrogen sulphide and carbon dioxide are the principal by-products from this process.

As in steam reforming of natural gas, this technology is well-developed and in a significant use. Product costs are sensitive to the location of the plant relative to the liquid hydrocarbon feedstock, the hydrocarbon selected (light oils, heavy oils, naptha, etc.), and the economic context into which the system is placed. For example, a heavy oil-based system located near a heavy oil resource will produce hydrogen at a price significantly below a naptha-based process in a location requiring rail or truck shipment of the feedstock.

2.1.3 Coal Gasification

When heat is applied to organic matter, such as coal, in the absence of sufficient oxygen for full combustion, varying amounts of gases, liquids and chars are produced. Those technologies which emphasize gas production are termed gasification processes. There are numerous gasification processes commercially available. Several others are undergoing advanced research and development or initial commercial demonstration. The process conditions of each are often substantially different. To a large extent, the gasification process chosen will depend on the purpose for which the gas is produced.

- for methanol synthesis, a low to medium energy content (5.6 to 18.7 MJ/m^3) gas is sufficient. This gas may also be used for on-site combustion in industry after impurities are removed.
- a high energy content (25-30 MJ/m^3) gas maximizes the production of methane and is of sufficient heating value and quality to replace natural gas in off-site and distant combustion sites. Alternatively, hydrogen alone can be generated (Figure 2.4).

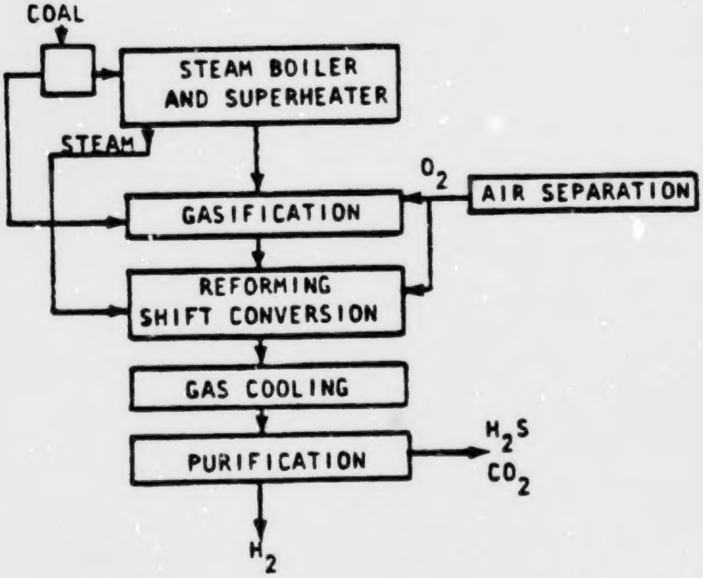

Figure 2.4 Generalized Process Flow for the Production of Gaseous Hydrogen from Coal (7)

The thermal efficiency, gas composition and throughput rates are substantially different, depending on the application required for the gas. Each system balances a number of variables to optimize the gasification process. These variables include the type of coal, pressure, temperature and the steam to oxygen or steam to air ratios.

High pressure (3.5 - 6.9 Mpa), high temperatures (1,000 to 1,300°C) and oxygen blown gasification conditions are typical of the process requirements for high energy content gas output. Depending on the process, coal enters the gasification chamber where it is broken down into hydrogen, carbon dioxide and byproducts including ash, slag, phenols, tars, creosols, sulphur compounds, particulates and hydrocarbons. The gas stream is purified to the desired level and in the case of synthetic natural gas production, hydrogen and carbon monoxide are catalytically reacted over a nickel based catalyst to produce methane.

The economic potential for producing synthetic natural gas from coal is limited by the availability and low prices of naturally occurring natural gas. The gasification of coal to produce hydrogen has a potential near to medium term application for upgrading bitumen from tar sands, heavy oil or coal in liquefaction processes. The main competition for this application will remain steam reforming natural gas and potentially electrolytically produced hydrogen.

2.1.4 Thermochemical Processes

The thermochemical decomposition of water into its constituent hydrogen and oxygen molecules has been investigated for two broad classes of processes: "open loop" systems and "closed loop" systems.

- open loop systems use chemical feedstocks which are transformed into byproducts of increased value, while at the same time producing hydrogen and/or oxygen.

- closed loop systems are cycles with intermediate chemicals from multi-step reactions recycled back into the processing loop as hydrogen and oxygen are produced.

Of the two processes, open loop systems have received far less investigation and appear to be in a class of systems of theoretical interest only.

In its purest form, a thermochemical process would have system inputs consisting of only feedstock water and thermal energy. A practical limitation is the availability of an extremely high temperature source of heat. Temperatures in excess of 2,000 K are required, a condition which far exceed commercially available technology. Closed loop hybrid systems have been proposed to resolve this difficulty. Such processes use intermediate chemical reactions by the electrolysis of various chemical products of previous cycle steps which support subsequent chemical reactions. Hydrogen and oxygen are produced and all chemicals are reprocessed. A representative hybrid process is illustrated in Figure 2.5. The primary advantage of these cycles is the high thermal efficiency which may be theoretically obtained. Overall system thermal efficiencies, approaching 40 to 50 percent, have been suggested.

There are over 200 closed loop thermochemical processes which have been investigated. Most have been rejected on the basis of cost, materials requirements, temperature and/or pressure demands, reaction rates, equilibrium points or net energy efficiency[8]. Much of the early work performed in this field considered the use of nuclear energy as the primary energy source. More recently, investigations into using solar energy have been undertaken.

Despite extensive investigation in the United States and elsewhere, with significant industrial and government support, no successful thermochemical process of more than laboratory size has been demonstrated to date. The attractiveness of this technology is limited by the

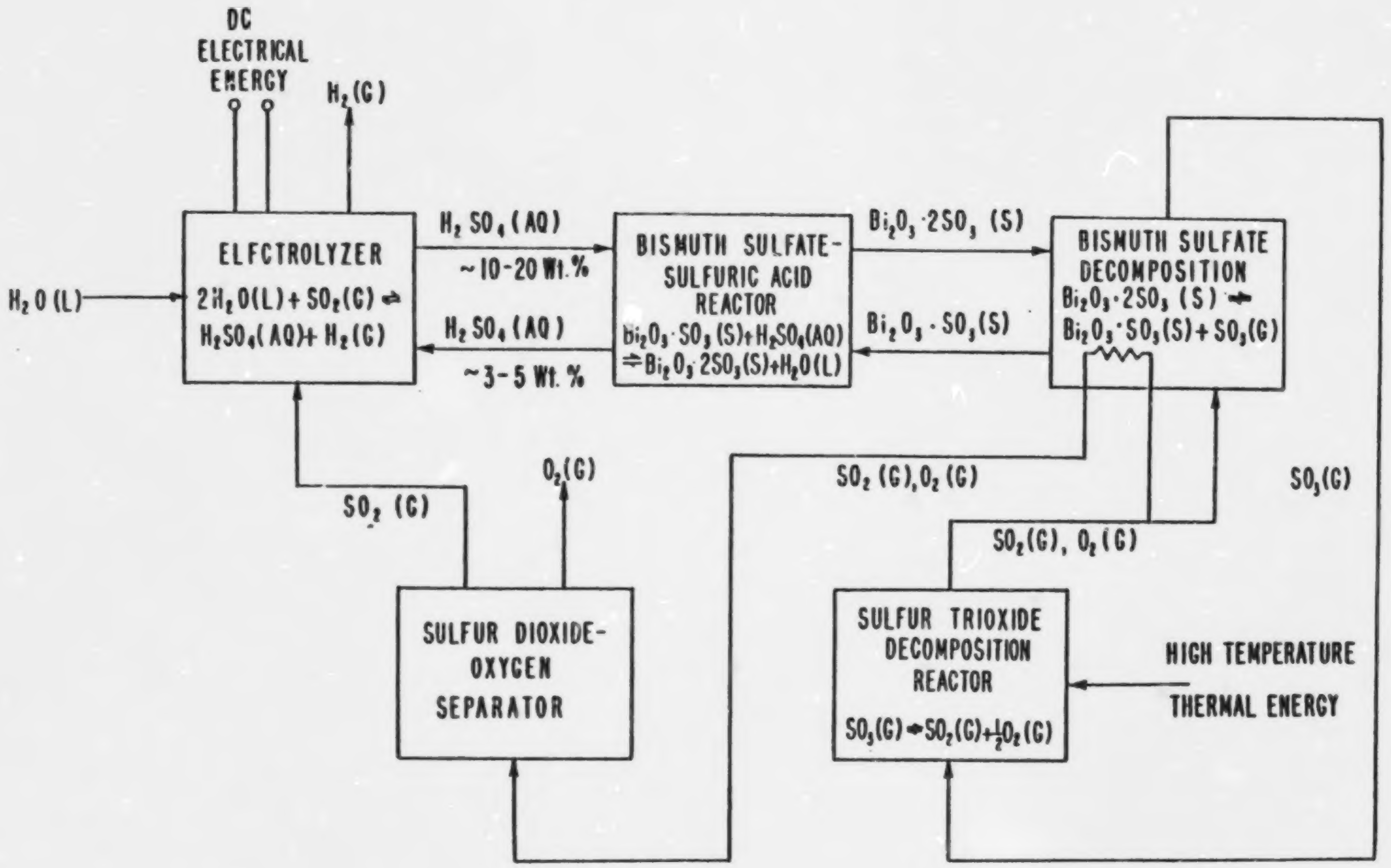
DC ELECTRICAL ENERGY
$H_2(G)$
$H_2O(L)$
ELFCTROLYZER
$2H_2O(L) + SO_2(G) \rightleftharpoons H_2SO_4(AQ) + H_2(G)$
$H_2SO_4(AQ)$
~10-20 Wt.%
$H_2SO_4(AQ)$
~3-5 Wt. %
BISMUTH SULFATE-SULFURIC ACID REACTOR
$Bi_2O_3 \cdot SO_3(S) + H_2SO_4(AQ) \rightleftharpoons Bi_2O_3 \cdot 2SO_3(S) + H_2O(L)$
$Bi_2O_3 \cdot 2SO_3\ (S)$
$Bi_2O_3 \cdot SO_3(S)$
BISMUTH SULFATE DECOMPOSITION
$Bi_2O_3 \cdot 2SO_3\ (S) \rightarrow Bi_2O_3 \cdot SO_3(S) + SO_3(G)$
$SO_2\ (G)$
$O_2(G)$
$SO_2\ (G), O_2\ (G)$
$SO_2(G),\ O_2(G)$
$SO_3(G)$
SULFUR DIOXIDE-OXYGEN SEPARATOR
SULFUR TRIOXIDE DECOMPOSITION REACTOR
$SO_3(G) \rightarrow SO_2(G) + \frac{1}{2}O_2(G)$
HIGH TEMPERATURE THERMAL ENERGY

Figure 2.5 The Los Alamos National Laboratory's Hybrid Bismuth Sulfate Thermochemical Hydrogen Production Process Flow Sheet

requirement to handle hazardous materials, at high pressure and temperature, within a highly complex system. Improvements in competing technologies such as water electrolysis have slowed research activities. There is little work proceeding in this field at the moment. No reliable information on the economics of the various processes is available and the probability of a significant breakthrough in either technology or economics is unlikely.

2.1.5 Electrolysis of Water

The simplest and cleanest method for producing hydrogen is the electrolysis of water. Electrolytic cells operate with essentially no moving parts, consisting principally of two electrodes, an electrolyte, and diaphragms or separators. Since the cells require electric power as the energy source, electrolytic hydrogen processes are limited by the carnot efficiency of thermal power generating plants, where this is the supply of electricity. Where generation occurs with hydro-electric, solar or wind sources, this particular limitation does not occur. Electrolytic hydrogen can be regarded as an "energy-carrier" for the electric production facility. In fact, electrolytic hydrogen has been referred to as "storable electricity".

At present, four major electrolyzer types exist:

1. Unipolar - with alkaline electrolyte (tank type)
2. Bipolar - with alkaline electrolyte (filter-press type)
3. SPE - a bipolar electrolyzer with a solid polymer electrolyte
4. Novel designs - for the electrolysis of high-temperature steam, impure water of water vapour.

Unipolar (Tank) Electrolyzers

This configuration, shown in Figure 2.6, has the active electrolytic

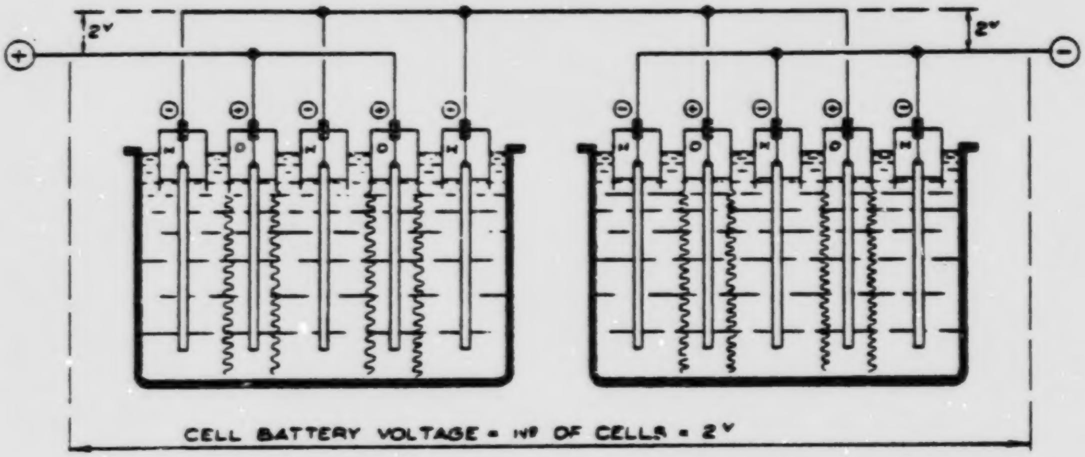

Figure 2.6 Tank Type Electrolyser Design Layout. (Electrolyser, Inc., Toronto.)

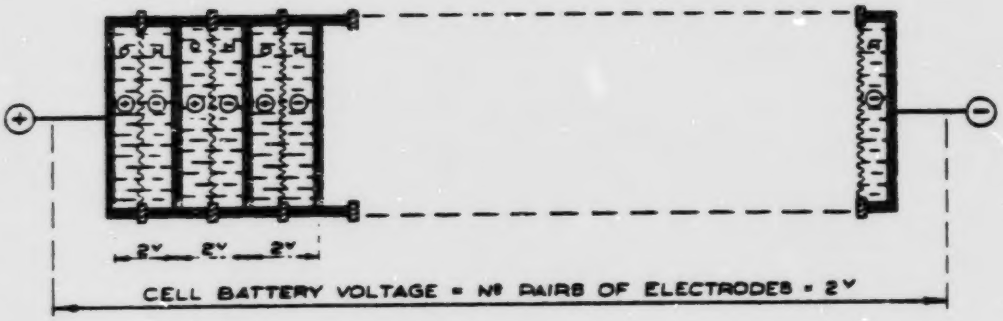

Figure 2.7 "Filter Press" Electrolyser Design Layout Used in Both Alkyline and Solid Polymer Electrolyte (SPE) Systems

components supported in an open container (tank) of electrolyte. Electrodes of the same polarity are connected electrically so that the entire tank unit has about 2.0 V applied across it to provide relatively high current flow. Individual tank units can be connected in series or in parallel in modules.

The tank type unit generally costs less to construct than the filter-press unit described below, and optimizes the capital cost/efficiency trade-off at somewhat lower current density levels than does the structurally more sophisticated, higher cost filter-press system. In the tank unit, individual cells can be isolated for repair and maintenance.

Bipolar (Filter-Press) Electrolyzer

The filter-press or bipolar electrolyzer configuration is used by the majority of the manufacturers. As illustrated in Figure 2.7, the bipolar system consists of a stack of cells electrically connected in series. For a typical cell stack, the applied voltage is the sum of the individual cell voltages (each about 2.0 V, or slightly lower). This can be several hundred volts, at a corresponding lower current rating as compared with tank-type unit installations. Each electrode has an anode and a cathode face at opposite polarities, hence the "bipolar" descriptor. Filter-press electrolyzers are more compact than tank units and more amenable to operation at elevated pressure. Unlike the tank units, should a cell failure occur, the entire stack must be shut down for repair. Filter-press electrolyzers usually present higher capital costs per unit active area (electrode) and, accordingly, they tend to be operated at higher current densities; this tends to reduce their efficiency advantages.

Solid Polymer Electrolyte (SPE) Electrolyzers

SPE electrolyzers are usually configured in the "filter-press" layout. This system uses a separator material which provides for ionic exchange directly within the solid material. Only water is circulated within the cell. Technically, the SPE is classified as an acid electrolyte system. The electrode is either integrally imbedded in the surface of the ion-exchange material, which acts as a separator, or takes the form of separate sheets of metal sandwiched between the SPE material.

Several advantages of this system include: a very thin sheet of electrolyte can be used, which allow low cell resistance and compact cell stacks; the elctrolyte is entirely captive and cannot be lost from the cell by carry-through or leakage; and very high current densities can be used, which minimizes the amount of the expensive SPE material required.

Electrolysis of water is a fully commercial technology in use worldwide, ranging from very small to very large scales of production. Examples of representative large-scale installations are listed in Table 2.1.

The industry is presently concentrating on improving operating efficiencies and reducing capital costs. A major Canadian manufacturer, Electrolyzer Corp., and Noranda, have formed a team to develop this technology and have demonstrated significant improvements in performance.

The cost of electricity is the principal determining factor in the cost of electrolytic hydrogen. A cheap source of electricity, from nuclear or hydroelectric generating facilities, for example, is a prerequisite to produce hydrogen at a cost which is competitive with other technologies, such as steam reforming natural gas.

2.1.6 Other Production Technologies

There are many other technologies which are under investigation and development. For the most part, they do not use fossil fuels as the source of energy. The various possibilities are characterized in Figure 2.8. The figure distinguishes between primary energy conversion tech-

TABLE 2.1

REPRESENTATIVE LARGE-SCALE ELECTROLYTIC HYDROGEN FACILITIES (2)

Location	Manufacturer	Hydrogen Output (000 m^3/hr)	Power Input MW	Year Built
Rjukan, Norway	Norsk-Hydro	62.3	250	----
Kima, Egypt	DeMag (BBC)*	39.6 (15.6)	170 (65)*	1960 (1972)*
Nangal, India	De Nora, SpA	31.5	130	1958
Cuzo, Peru	Lurgi GmbH	5.7	25	1958

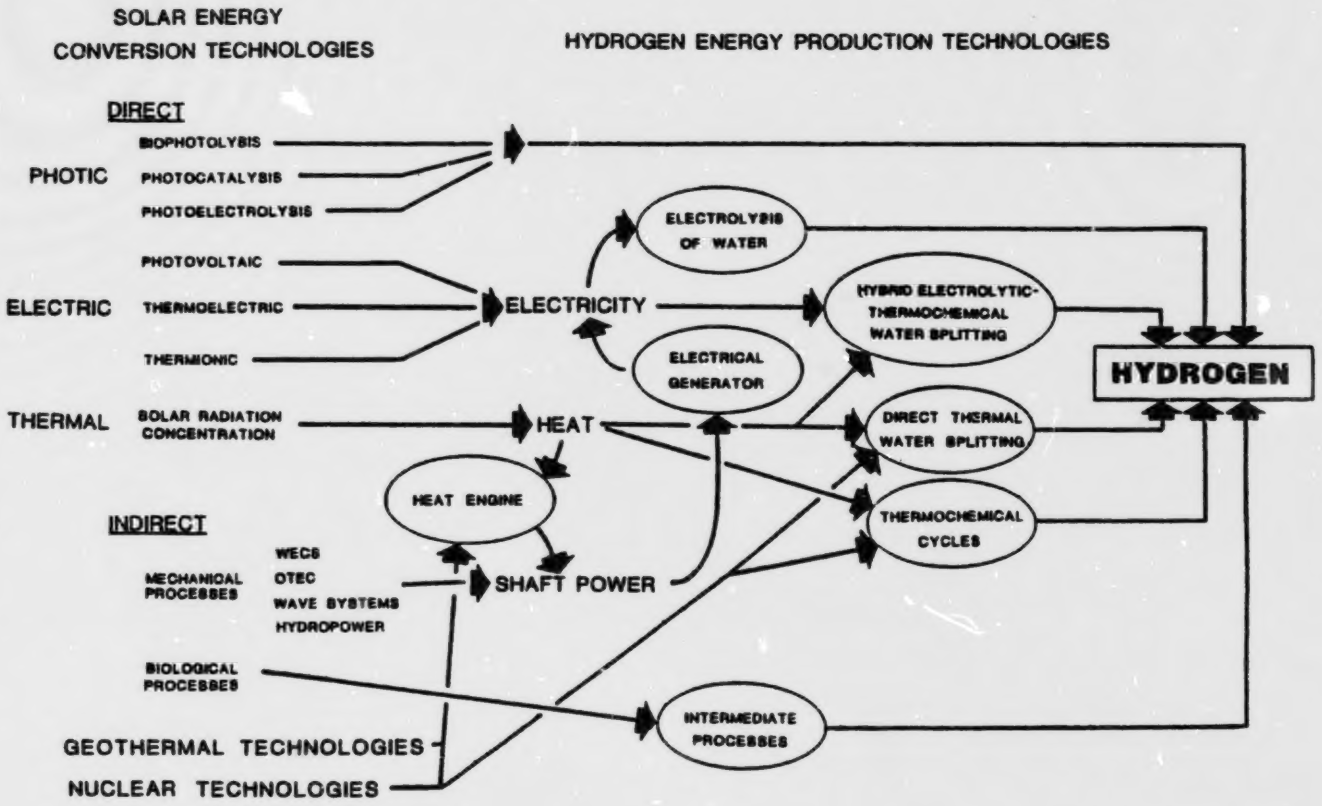

Figure 2.8 Modes and Paths for Converting Non-Fossil Energy into Hydrogen.

nologies (PECTS) and hydrogen energy production technologies (HEPTS). The PECTS shown to the left of the figure utilize solar energy, geothermal or nuclear technologies as energy sources. The HEPTS, shown to the right of the figure, are technologies which, in combination with PECTS, create a conversion path leading to the production of hydrogen. Each path denotes a distinct system possibility.

Electrolysis of water, for example, is categorized as a HEPTS, as it relies on the availability of electricity. The figure indicates the various PECTS options which could supply that electricity.

While many of the PECTS options shown in Figure 2.8 are conceptually and theoretically interesting, most can be disqualified from consideration as practicable commercial technologies within at least the next two decades. These include:

- Biophotolysis - these systems use biological mechanisms to convert solar radiation into hydrogen. Water is used as an electron source for the biological process of direct photoreduction of hydrogen. Fresh and salt water systems are under evaluation. Commercialization prospects are considered remote.

- Photocatalysis - these systems combine water, solar radiation and catalysts to produce hydrogen. Compound salts, compound semiconductors or photosynthetic dyes decrease the transparency of water in order to increase the proportion of sunlight wave lengths capable of directly dissociating water. Back reactions, catalyst breakdowns and low efficiencies are problems which must be overcome.

- Photoelectrocatalysts - electrical power is introduced to improve the efficiency of photocatalysis systems and increase the stability of the reaction.

- Thermoelectric - this system produces electricity by generating voltage between the junctions of two dissimilar metals when a temperature difference exists between them. Such systems are likely to be of interest only in low power and remote locations.

- Thermionic - thermionic converters produce electricity directly from heat. These units have been applied to space power programs but have low efficiency, power output and short operating lifetimes.

- Direct Thermal Water Splitting - as the temperature of water vapour is raised to 2,000 K under low pressure, the water vapour will dissociate into hydrogen and oxygen molecules. Obtaining such high temperatures and collecting the molecular products are limiting factors. This technology is at present confined to laboratory testing.

- Ocean Thermal Energy Conversion (OTEC) Systems - the scale and cost of OTEC powerplants are directly related to the temperature differential between surface and depth waters. The required temperature differential is not available in any Canadian water body.

These systems are disqualified from Canadian consideration because alternative hydrogen production systems already exist which have higher energy conversion efficiencies than these technologies have achieved to date or are projected to achieve in the near to medium time frame. As indicated in Figure 2.9, most of these technologies are in a "research" phase. Their development, demonstration and commercialization remains to be accomplished. These requirements characteristically take decades.

Site-specific considerations, such as remote power generation, might provide "niches" where several other technologies, shown in Figure 2.8, may find application. These "marginal" technologies include:

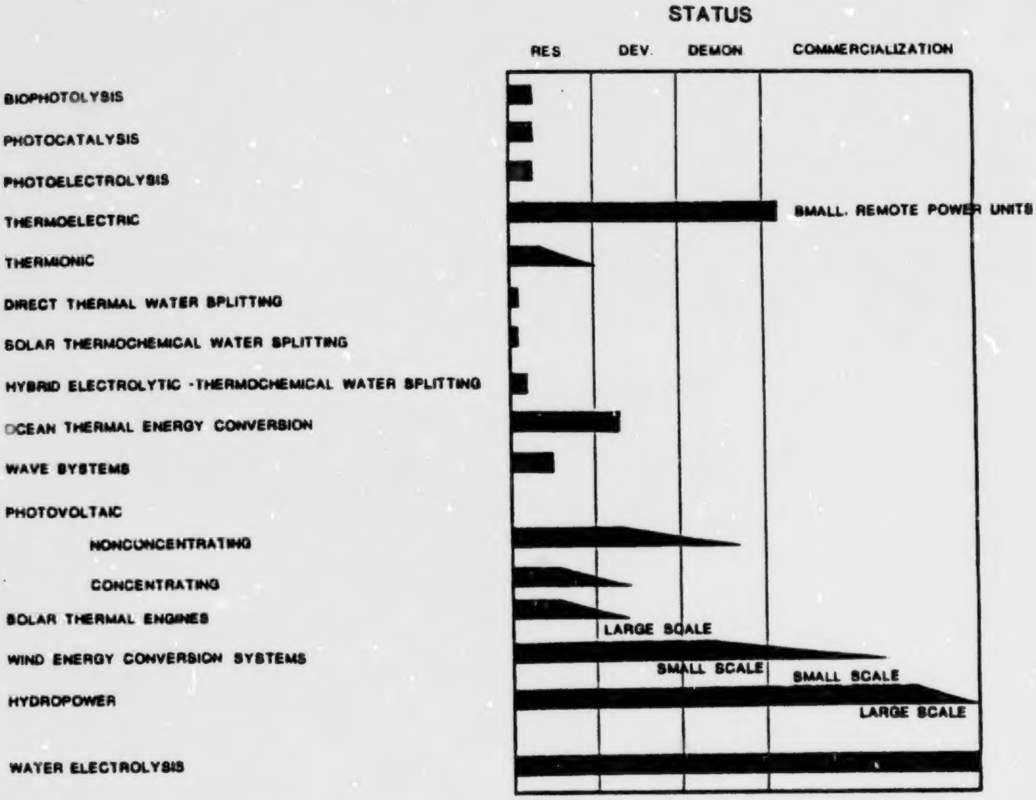

Figure 2.9 Research, Development, Demonstration and Commercialization Status of Applicable Technologies (2)

- Photovoltaic Systems
- Solar Thermal Engines
- Tidal Power Systems
- Geothermal Power

The limited solar resource base will limit the attractiveness of photovoltaic and solar thermal engine systems in large-scale, centrally-located installations. The potential for tidal systems on the west coast will be limited by the suitability of the available coastline but, more significantly, by the close proximity of major fossil-fuel resources. On the east cost, electrical power generation may have preferential application to provide power to the local grid or for export markets if the electricity can be produced at a competitive rate. Depending on the electricity costs of projects such as the Fundy Tidal project, hydrogen through electrolysis may be practicable. The amount of geothermal energy is not sufficient to produce a significant impact on the energy mix in Canada and is unlikely to find any application as an energy source in the production of hydrogen.

From the possibilities indicated in Figure 2.8, there are only three power systems which are attractive options to supply the energy required for hydrogen production.

- Hydropower Systems
- Nuclear Systems
- Wind Energy Conversion Systems (WECS)

The large-scale hydro resource base is significant, but resource availability to support small-scale hydropower requires further investigation. Small hydropower systems are particularly appropriate for remote power generation. Hydrogen as a medium of energy storage, or perhaps used in intermediate synthesized fuels such as ammonia, might eventually provide a means of supplementing or displacing petroleum distillate-powered generating equipment systems.

Matching large-scale hydropower systems to electrolyzers is a commercially proven technology. Matching nuclear power systems to electrolyzers has not been accomplished on a large scale but will not require the development of new technology. This cannot be said of small-scale hydropower systems. The literature does not indicate that an interface between small-scale hydropower and electrolyzers has been accomplished to date.

The technology of wind generation on a small scale is in an advanced state of development compared to large-scale systems. When adequate wind regimes are available, designs for large-scale equipment systems capable of providing efficient operation are available. The reliability of large-scale wind systems has not yet been demonstrated but research underway should establish this factor in the immediate future.

2.2 TRANSMISSION/DISTRIBUTION TECHNOLOGIES[1,13,14,15]

Hydrogen can be transmitted and distributed to end users as a cryogenic liquid or as a gas, using pipelines, rail tanker or trucks. The experience record for pipelines is limited, while rail tanker and trucks are routinely used today in merchant hydrogen markets.

2.2.1 Pipelines

Several pipeline options exist: transmission as a gas, as a blend with natural gas or as a cryogenic liquid.

Gaseous Hydrogen

High-pressure pipelining of gaseous hydrogen appears feasible and has been studied extensively.[1,13] These studies indicate that transmission of hydrogen will be more expensive than natural gas, primarily because hydrogen is substantially bulkier on an energy basis than natural gas. As a result:

- the compressors must be larger than those required for natural gas
- larger pipeline sizes and/or higher compressor pressures will be required to sustain an equivalent energy flow

Hydrogen has a significantly lower density than natural gas, and carries only one-third as much chemical energy on a volumetric basis (12.1 GJ per m^3 vs about 37.3 GJ per m^3 higher heating value (HHV)) at atmospheric pressure. At elevated pressures, the ratio increases from 3:1 to about 4:1 due to the differences in compression requirements for the two gases. However, pipeline diameter need not be scaled up to the same extent in a move from natural gas to hydrogen. Hydrogen's other physical properties, especially its viscosity, are favourable, allowing the specific flow rate (i.e., speed of the gas in the pipe) to be raised considerably over the conditions optimum for natural gas. This leads to only a moderate increase in pipeline size (or a modest reduction in gas energy delivery rates) for hydrogen at a given pressure.[14]

Centrifugal compressors are not naturally suited for use with hydrogen. Piston type compressors are suitable with minor modifications in materials.[15] The conversion of piston engines to operate on hydrogen has not been accomplished to date, but should not present significant technical problems based on research involving smaller-scale hydrogen powered piston engines.

An example of an existing system is the Chemische Werke Huels, which operates an extensive hydrogen pipeline system in the Ruhr district of Germany. This system is illustrated in Figure 2.10. The pipeline was constructed before WWII and is 206 km in length.

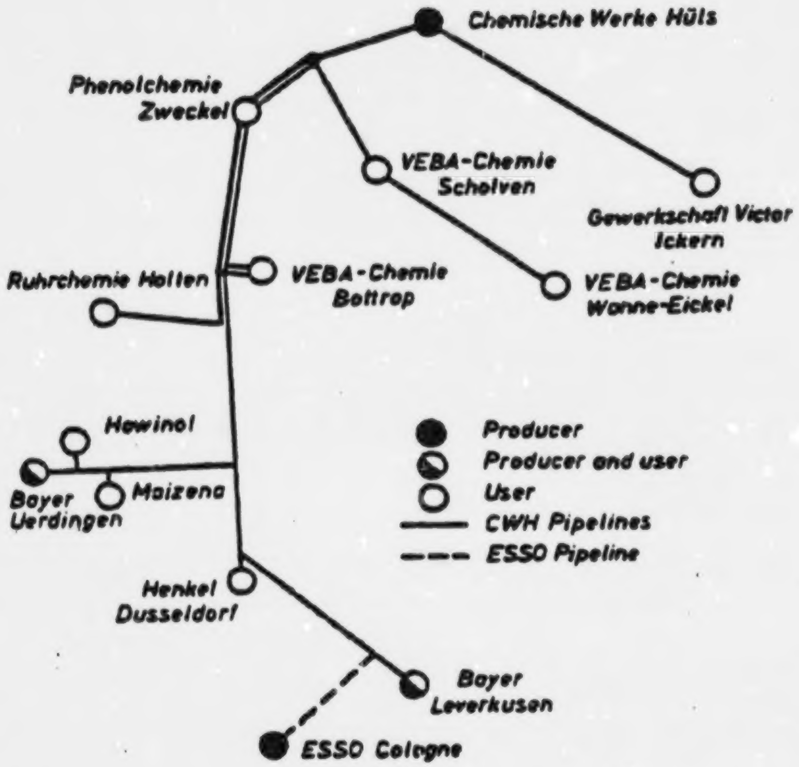

Figure 2.10 The 206 Kilometer Chemische Werkes Huels Hydrogen Pipeline in the Federal Republic of Germany Ruhr Area (15)

Natural Gas/Hydrogen Blends[17]

A potential near term application of the gaseous hydrogen pipeline concept is to supplement natural gas with up to 10 percent hydrogen by volume. Although the emphasis of this concept is to substitute hydrogen for natural gas, it can also be viewed as an alternative method to deliver hydrogen. In this application, there must be a capability to separate the hydrogen from the mixed-gas systems. This may be accomplished at the point of delivery by several methods.

One approach is cryogenic separation. A second approach is to use metal hydride systems as a means of extracting hydrogen preferentially from the mixed-gas stream. A third possibility is a pressure-swing absorption process. All these options need considerable additional research to be practicable. This general approach is potentailly attractive as a transition option where natural gas transmission is phased out and hydrogen is progressively introduced to meet energy demand.

The 10 percent supplement limit is set by existing gas metering and burner systems. An addition of 10 percent can be tolerated without reorificing or otherwise modifying basic natural gas combustion equipment. Beyond this limit, burner equipment would require rejetting. In view of the number of natural gas burning devices presently in use, this would represent a significant undertaking.

Cryogenic Liquid

Preliminary assessments have been carried out on the transmission of liquid cryogenic hydrogen in a suitably insulated pipeline. Although this approach may have merit, the cost of a conventional double-walled, vacuum-jacketed pipeline will be prohibitively expensive for long-distance transmission. Several unconventional approaches explored for natural gas systems such as supercritical, cold-phased transmission using lower cost, conventionally insulated pipelines, have not been studied in the hydrogen context.

An approach that has been suggested by a number of researchers is a combined cryogenic hydrogen underground pipeline and electrical transmission lines. The electrical conductor would profit in a greatly-increased power rating by being in the cryo-resistive or superconductive state as induced by the temperature of the cryogenic hydrogen. Electrical and gas-energy utility interests might then be jointly served by the combined energy type and costs shared accordingly. This advanced concept appears to deserve further assessment.

2.2.2 Rail and Highway Transportation

The transportation of liquid hydrogen in cryogenic rail tank cars is an established commercial practice. Highway trailer delivery of both liquid hydrogen and over short ranges, high pressure gaseous hydrogen, is also routinely accomplished. For bulk transport, cryogenic liquids are preferred over the gaseous tube trailer. Highway trailers carrying hydrogen may carry as much as 50,000 L. Specially designed trailer units of up to 64,000 L have been used by NASA in transporting liquid hydrogen to Cape Kennedy. Tail tanker cars may carry 105,000 L per car.

The delivery of high-pressure hydrogen in cylinders, whether in individual cylinders or large-volume, high-pressure storage tanks in tube trailers, is the most expensive means of delivering hydrogen. A rough estimate is that delivery in high-pressure cylinders adds about 75 cents per GJ per km. Bulk delivery in liquid form involves significantly lower transportation costs. This consideration, combined with the customer's demand rate, often dictates the market area that can be served by these alternative delivery methods.

2.3 STORAGE TECHNOLOGIES

2.3.1 Pressure-Vessel Storage

The oldest technique for storing hydrogen is containment of the gas at ambient temperature in a fabricated container, usually of metallic construction. The storage pressure is a key variable, ranging from near-atmospheric pressure used in "gas holder" type containers, to pressures of 69,000 to 100,000 kPa for certain aerospace facility applications. Pressure vessels, both stationary and mobile, are in widespread use in the delivery of hydrogen to merchant markets.

Hydrogen is one of the most difficult and expensive gases to store because of its low density. This is illustrated in the example of a standard welding bottle containing a nominal 6 m^3 of hydrogen. The filled tank weighs approximately 56 kilograms but holds less than 0.5 kilograms of hydrogen. This weight factor limits the amount of hydrogen that can be delivered in pressure vessels. In some circumstances, for example where high-pressure hydrogen is needed but the volume to be handled does not justify a liquid-to-gas conversion system, delivery in pressure vessels can be justified.

A study conducted by the Electric Power Research Institute[18] assessed various kinds of hydrogen storage techniques applicable to local electrolytic production of hydrogen from off-peak electrical power. Table 2.2 presents the general technical requirements and estimated costs in 1975 U.S. dollars of gaseous hydrogen storage systems at three different pressure levels for seamless steel pipeline material.

There are alternative and more advanced materials than seamless steel capable of operating at higher pressures and with lower vessel weights. These include high alloy steel containers and filament wound containers. These technologies can be characterized in terms of the weight of the

			(1975 U.S. Dollars)			
Storage Pressure, psi	Vessel Size	No. of Vessels Required to Store 1 Million SCF	Vessel Cost	Mounting Cost	Manifolding Cost	Total Cost for 1 Million SCF, $\$10^6$
			$			
500	24-in. OD 40-ft. long	265	3300	540	250	1.08
1295	24-in. OD 40-ft. long	116	3500	540	275	0.50
2450	24-in. OD 20.5 ft. long	136	3900	540	300	0.65

Table 2.2 Estimates of Aboveground Steel Pressure Vessel Storage Systems for Gaseous Hydrogen (18)

hydrogen that can be stored at a given pressure vs the tank weight required for that storage. The standard welding bottle discussed above holds approximately one percent by weight storage density. High alloy steel and composite materials storage vessels can achieve a five percent storage density. This storage technology can be compared directly to hydride storage, to be discussed later, which also falls into the same two classes of storage density of one percent and five percent. The upper limit on storage density is set by liquid hydrogen stored in cryogenic vessels which can achieve a 15 to 20 percent storage density.

The technology is well developed and utilized on a commercial basis worldwide. No significant improvements are expected. The major progress that might be made is to reduce equipment costs through large volume production of certain classes of cylinders required to support the use of natural gas in 13 800 kPa systems in automotive transportation.

A unique materials engineering problem associated with high-pressure storage of hydrogen is materials compatibility. Conventionally forged low-alloy steel gas storage cylinders, such as used for small-quantity industrial merchant hydrogen gas deliveries, are not known to be susceptible to hydrogen materials compatibility effects. However, cases have been reported where hydrogen vessels with lower safety factors and/or those with weldments of other-than-forged construction have suffered failures.

Substantial progress has been made in evaluating the practical ramifications of the effects of hydrogen on materials of all types. Solutions to these materials problems are attainable. The unique materials problems associated with high-pressure hydrogen service have been the subject of extensive study. These problems are not "all encompassing", but do affect particular design approaches with particular alloys, under particular operating conditions. The investigation of pipeline materials for hydrogen service, in particular, deserves further study. Identified alternative methods of operating practice in pipeline systems design engineering should provide practical solutions leading to the design of effective, long-lived pipeline distribution systems.

Although materials engineering problems do exist in hydrogen storage applications at high pressures in low-strength, high-toughness materials, design alternatives and general design practices have been developed that enable these problems to be coped with effectively.

The main advantage of high-pressure storage is its relative convenience. The most significant disadvantage is the requirement for expensive high-pressure compressor equipment and the weight of the storage containers. Aside from material problems considerations, high-pressure gaseous fuel storage systems have an excellent safety record.

High-pressure storage bottles are commercially available in size ranges from cubic centimetres to hundreds of cubic metres. An example of large hydrogen storage vessels constructed for NASA is a laminated, thick-walled tank of 42 cubic feet volume or more, designed to store gaseous hydrogen at 34,500 to 60,000 kPa. The investment in this tank, in the mid 1970's, was over $250,000. However, this tank system also provides an example of the impact of materials considerations in that the "hydrogen embrittlement" phenomena, discussed earlier, led to the derating of this tank system to 17,000 kPa.

2.3.2 Liquefaction and Storage

Conventional Liquefaction Technology

The liquefaction of hydrogen is a more complicated refrigeration challenge than most other cryogenic processes. The reason is that the

Joule-Thomson inversion temperature for hydrogen is extremely low at 202° Kelvin. If compressed hydrogen gas above this temperature is expanded, its temperature will rise. Below this temperature, the gas will cool as necessary for liquefaction. Therefore, it is necessary to directly precool hydrogen below this temperature before it can be liquefied by the usual approach of free expansion. Current liquefaction technology is well advanced and no technological problems should exist in large-scale liquefaction. Advances can be expected that will increase liquefaction efficiency.

A description of the various liquefaction processes is provided below[19]:

> "The basic principles concerned with hydrogen liquefaction are shown on three separate flowsheets; the first, Figure 2.11, shows a simple Joule-Thomson cycle. This process involves the precooling of the hydrogen feed and recycled refrigerant against liquid nitrogen followed by a Joule-Thomson expansion, which forms liquid hydrogen product. The efficiency of this cycle depends mainly on the liquid nitrogen temperature level, which is reduced to below the normal atmospheric boiling point by a means of a vacuum pump.
>
> "A flowsheet of a more complex Joule-Thomson cycle is shown in Figure 2.12. Larger plants having greater production capacity are designed for reduced power consumption by precooling the hydrogen against atmospheric as well as vacuum boiling liquid nitrogen in a staged manner. Additional savings may be realized through a double Joule-Thomson flash of the hydrogen. An Expander Cycle is shown in Figure 2.13. This type of cycle precools the hydrogen with cold gaseous nitrogen and boiling liquid nitrogen. The boiling liquid nitrogen may be at super-atmospheric pressure, atmospheric pressure or under vacuum conditions on optimization determinations. Below the nitrogen precooling level, additional refrigeration input is by means of an expansion engine. This expander may be a reciprocating or centrifugal engine, depending on the operating pressure selected for this cycle. Below the expander level, the refrigeration input is normally by means of a Joule-Thomson expansion in two stages. The expander cycle may take advantage of staged conversion to increase the cycle efficiency to a greater extent than for simple or complex fuel cycles. Seven to nine converter stages have been used in the past. They have operated from the boiling liquid nitrogen temperature level progressively down to the final liquid hydrogen flash temperature level."

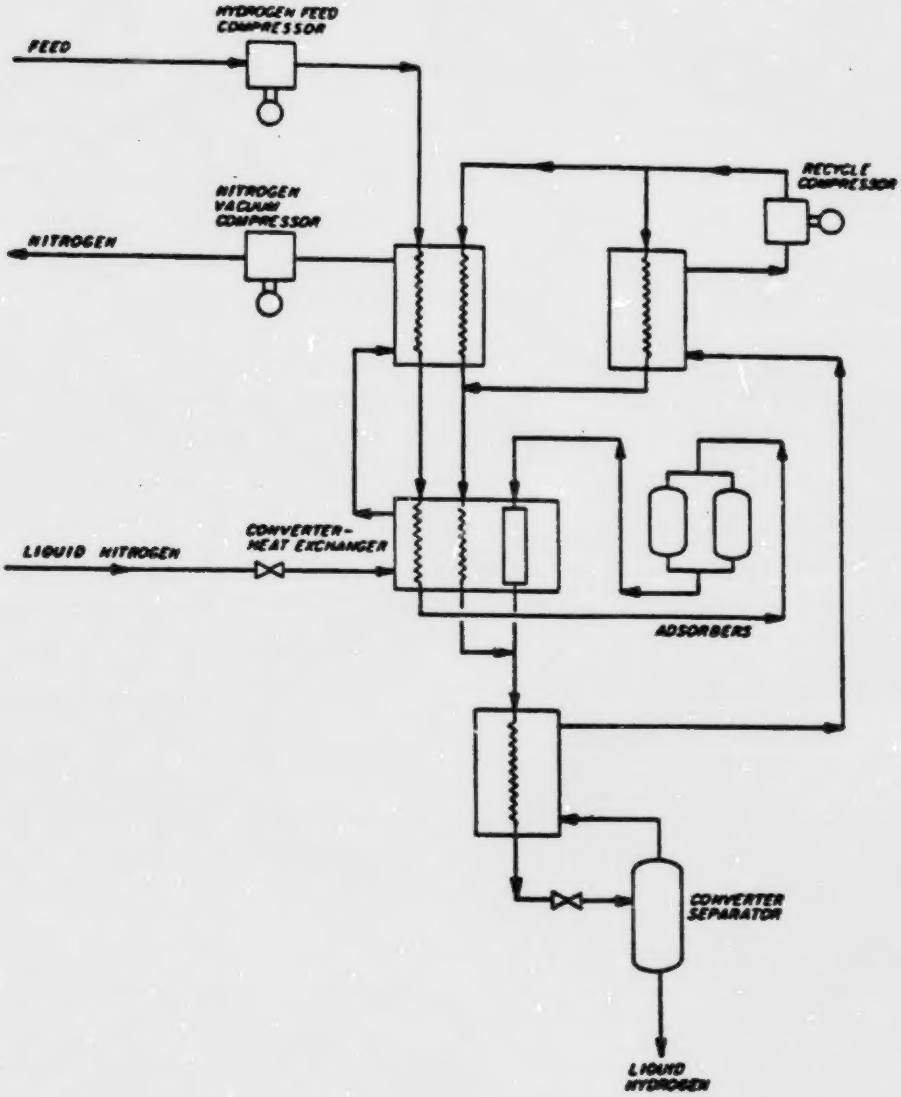

Figure 2.11 Simple Joule-Thomson Cycle Hydrogen Liquefaction System Process Flow Sheet (19)

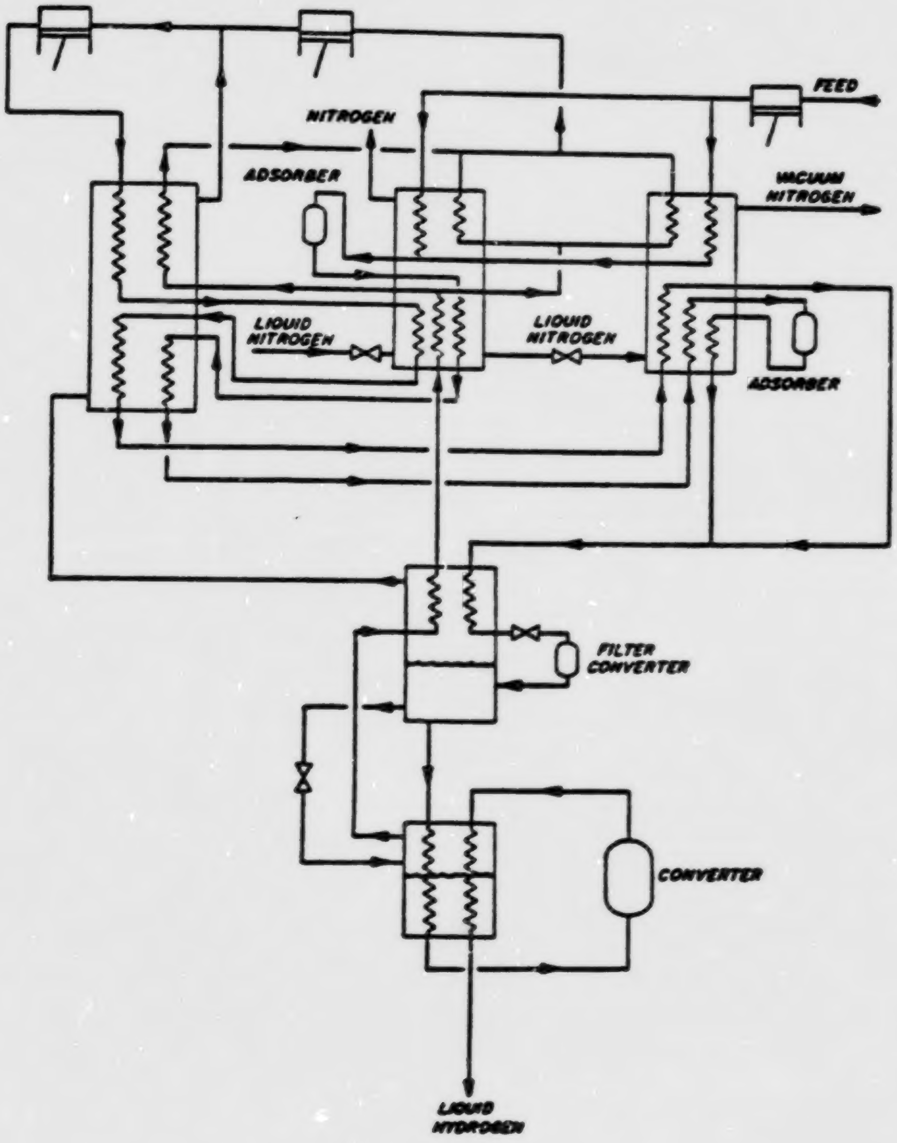

Figure 2.12 Complex Joule-Thomson Cycle Hydrogen Liquefaction Process Flow Sheet (19)

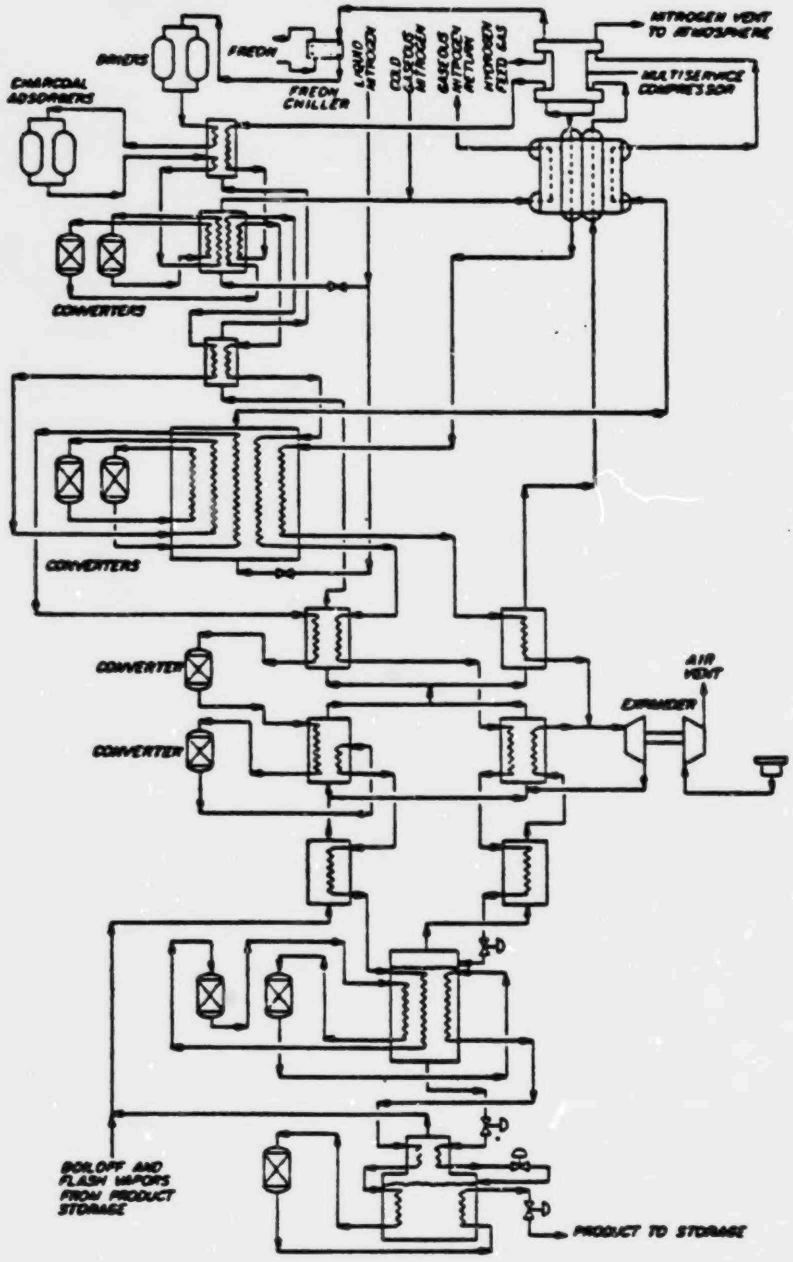

Figure 2.13 Expander Cycle Hydrogen Liquefaction System Process Flow Sheet (19)

Table 2.3 presents the power requirements and approximate production rates appropriate to these three types of cycles. It is apparent that increased performance in terms of energy required can be achieved only by increased system complexity, and thus higher capital costs and larger plant scales. This limitation will have a significant impact on the use of liquid hydrogen.

The Carnot efficiency of liquefaction equipment as a function of system capacity drops significantly as capacity rating reduces. This effect is particularly aggravated at the low capacity ratings associated with laboratory or other small-scale systems, but persists up to capacities of nearly 60 tonnes per day.

These limitations have led to a continuing search for an improved method of liquefying industrial gases generally and hydrogen in particular. Until recently, there did not appear to be any technology available capable of improving upon mechanical liquefaction systems. However, work done by Los Alamos National Laboratory (LANL) in the field of "magnetocaloric" refrigeration systems offers promise for such improvements. Because of the significance of liquefaction, and particularly inexpensive liquefaction, to the hydrogen energy concept, this promising but relatively undeveloped new technology will be discussed.

Magnetocaloric Refrigeration[20]

The construction principle of the magnetocaloric refrigerator is illustrated in Figure 2.14. A "wheel" assembly is constructed of segmented compartments of alloys of Gadolinium. As the wheel is rotated in the magnetic field of a superconducting magnet, heat is pumped across the wheel assembly. Wheel assembly and drive motors, etc., are mounted in a liquid helium cryogenic dewar.

This technology offers the potential of achieving Carnot efficiencies in the range of 70 to 80 percent. The process can operate at atmospheric

TABLE 2.3

POWER REQUIREMENTS FOR LIQUID HYDROGEN PRODUCTION

Process	Kilowatt-Hrs of Power per Pound of Liquid Hydrogen	Approximate Range of Production Pounds per Day	Pounds Liquid Nitrogen Refrigeration per Pound Liquid Hydrogen
Joule Thomson cycle--simple	10	0- 4,000	11.6
Joule Thomson cycle--complex	8.7	4,000- 10,000	10.0
Expander Cycle	5.0*	6,000-120,000	

Note: The energy content of 1 pound of hydrogen is approximately 15 kWh

* Includes power for nitrogen liquid and cold gas refrigeration.

Source: Newton, Charles L., Hydrogen Production, Liquefaction and Use, Cryogenic Engineering News, August 1967.

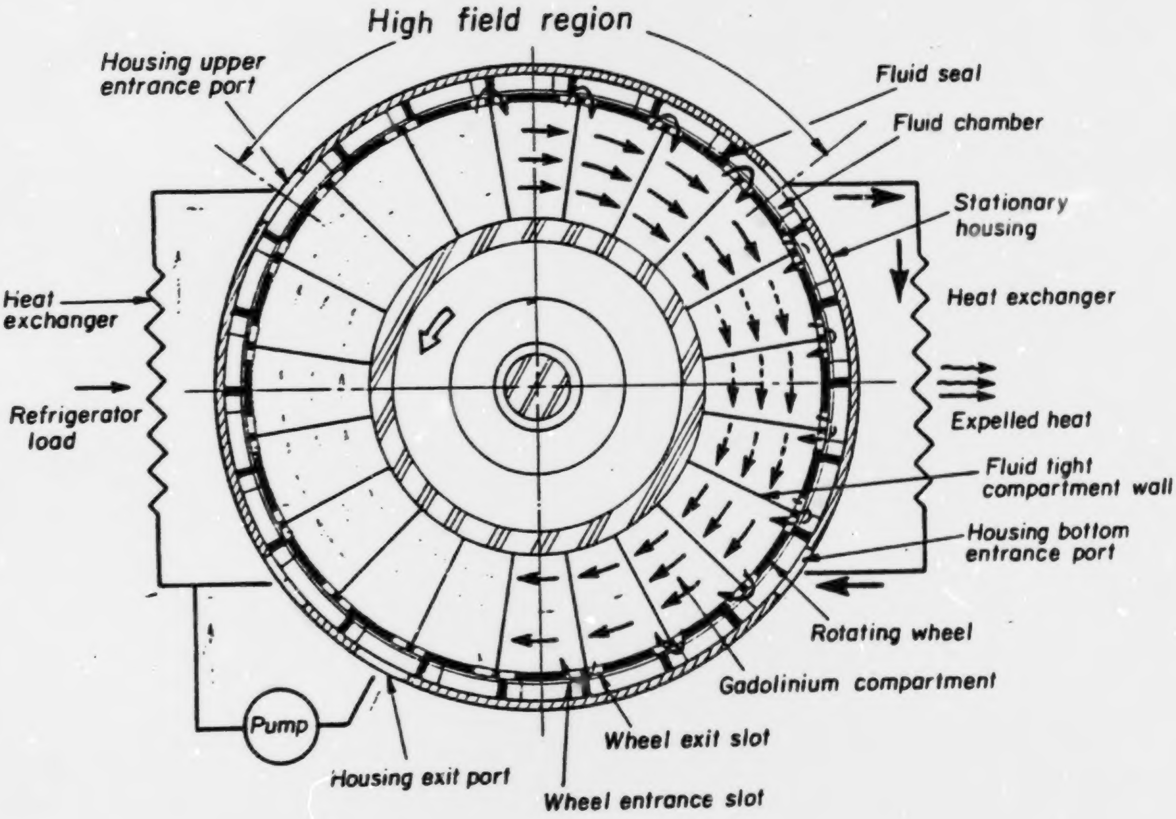

Figure 2.14 The Magnetocaloric Refrigerator "Wheel" Assembly (20)

pressure and requires only slow moving machinery with operational speed ranges in the range of several revolutions per minute rather than the tens of thousands of revolutions per minute associated with centrifugal expansion equipment. Equivalent capacity systems constructed using magnetocaloric technology may require equipment volumes one order of magnitude below that occupied by present technology based systems. Significant reductions in capital requirements and operating and maintenance costs can be expected if this technology can be introduced into commercial practice.

Key experiments providing the first accurate measurements of the efficiencies of this technique will be made during 1983 by LANL under NASA project sponsorship. This technology is also included as a subject of investigation for the newly formed Institute for Hydrogen Systems at the University of Toronto.

The direct reduction of liquefied hydrogen costs is the principal goal to be achieved. Cost reduction will be achieved through the reduction in initial capital investment requirements and operating and maintenance costs. Other costs resulting from energy losses associated with conventional liquefaction may be reduced by a factor of two or more. These costs may amount to 30 percent or more of product cost in large expansion liquefaction systems.

The most significant attribute of magnetocaloric refrigeration technology is that high process efficiencies can be achieved independent of scale of implementation. While parasitic losses will increase with smaller scale units, this effect will be only a minor contributor to efficiency loss.

Only where system efficiency is independent of scale is it possible to envision gaseous pipeline feed to small-scale liquefaction systems which could support small-scale distributed hydrogen using systems with economical on-site storage capabilities. This approach could have a major impact on the feasibility of using liquid hydrogen as a fuel in transportation systems. Storage of liquified hydrogen as compared to pressurized bottles and hydride storage systems is economically superior.

Storage of Liquid Hydrogen

The most efficient means to store liquid hydrogen (LH_2) is in double-walled dewar systems. Superinsulation systems have been developed to reduce heat leakage and hydrogen boil-off. Liquid hydrogen storage vessels of up to 150,000 litres use shop fabrication methods with subsequent rail or road transport to the installation site. Beyond this range, vessels are usually field-fabricated and are usually spherical in shape. The largest LH_2 storage vessel in existence today are the two 3.2 million litre, spherical containers located at the Kennedy Space Center.

Hydrogen storage dewars as large as 11.4 million litres of capacity may be required for hydrogen fueled aircraft applications. There are no known technical reasons why dewars of this size cannot be constructed, but their environmental and, particularly, their safety implications remain to be assessed.

This storage technology is quite mature and is commercially available around the world. Construction methods do not encounter the materials compatibility problem associated with high-pressure gaseous storage of hydrogen.

Few improvements are anticipated for large-volume storage tankage systems. Much work remains for low-volume storage systems which may be required in transportation fuel applications for automotive vehicles, heavy trucks, and buses. The work program of The Institute of Hydrogen Systems (IHS) at the University of Toronto will attempt to advance this technology.

2.3.3 Metal Hydride Storage

Metal hydrides offer a relatively new alternative for the collection, storage and handling of hydrogen. Although stable metal compounds (i.e., metal hydrides) have been known for many years, it has only been recently that metals have been developed that are easiliy charged with hydrogen at ambient temperature and modest pressure and capable of subsequent discharge. Metal hydrides identified to date consist of one-component metal systems for metals such as magnesium, vanadium and niobium, or alternatively are binary intermetallic compounds such as magnesium nickel alloys, iron titanium alloys, and lanthium nickel compounds.

These materials generally fall into two ranges of storage capability. The range typified by iron titanium alloys is about 1.5 percent weight hydrogen in the storage container. The range of magnesium nickel alloys is approximately 4 to 5 percent, but suffer from slow charging characteristics.

Metal hydride science is progressing from the theoretical and laboratory investigative level into pilot applications.

The first noteworthy pilot-scale hydride system was at the Brookhaven National Laboratory storage vessel/heat exchanger. This hydride system stored electrolytic hydrogen produced during off-peak electrical demand periods. The hydrogen was delivered to a fuel cell for electricity production during peak-demand periods. The unit stored about 6.4 kg of hydrogen in its 400 kg-charge of iron titanium hydride. A continuous discharge rate of 1.1 kg per hour permitted most of the hydrogen to be used.

The first automotive hydride system was designed and built in 1974 by the Billings Energy Corporation. The unit contained 100 kg of iron titanium hydride in two-inch diameter aluminum heat-exchanger tubes.

The usable hydrogen capacity was 1.5 kg, giving a 50 km fuel supply to the 1973 Chevrolet sedan in which it was installed. The heat of decomposition was supplied to the hydride from the engine cooling fluid.

Other designs have employed exhaust heated hydride systems. A novel means of supplying the heat of decomposition to a hydride was accomplished by Daimler-Benz which drew ambient air to a tubular hydride container and delivered cooled air to the passenger compartment of a bus.

Hydrides can be used to build simple compressor systems which can accept low-pressure hydrogen at a relatively low temperature and produce high-pressure air heated hydrogen. This design practice dates back at least 20 years. The first pilot-scale hydride compressor designed by MPD Technology Corporation in the U.S. and the Denver Research Institute accepted a continuous 0.8 litre per second hydrogen flow at one atmosphere and a discharged gas at 120 atmospheres. Heating is supplied by electricity through an automatic control system. Cooling is accomplished by air-blowers operating at local ambient temperature conditions.

Hydride storage systems can be considered to be available as commercial products. However, this commercial activity has been carried out at a rather low level and does not involve large-scale systems.

Little data is available on the economics of hydride storage of hydrogen. These costs can be generally characterized, however. Prices for iron titanium and ternary-modified nickel-mischemetall material range from $6.50 to $8.50 per kg in quantities greater than 500 kg in 1980 U.S. dollars. Capital costs are estimated to be $40 per kg of hydrogen stored in a fixed-bed hydride system operating at 32 atmospheres, assuming a source of high-pressure hydrogen and availability of low cost iron titanium.

The charged hydride ranges from about one weight percent for rare-earth pentanickel-hydrides to about five weight percent for magnesium-based hydrides including container weight. Actual transportation costs must be researched on an individual point-to-point, tonnage and commodity-classification (not established for hydrides) basis. If hydrides are used for over-the-road transportation of hydrogen, for any purpose, an additional cost of possibly up to 70 cents per GJ per km might be required. Such costs would be difficult to justify except in special circumstances. The present use of tube trailers for compressed hydrogen gas carries a similar transportation cost penalty as was previously discussed. Metal hydride transportation of hydrogen may compete with compressed gas tube trailers, or equivalent rail systems, if hydride alloy capital costs can be offset by the reduction or elimination of compressor equipment capital and operating maintenance costs.

Safety is the primary advantage of metal hydrides. From this standpoint, this method of storage is advantageous over high-pressure bottles and cryogenic systems.

Among the potential negative environmental aspects of hydride is the possible toxicity of fine, active powder, both from an industrial handling point of view and through tank spillage in populated areas. Spent hydride disposal may also pose an environmental problem. This subject remains unexplored. Some hydrides become pyrophoric when cycled several times. Magnesium, for example, may burn intensely if suddenly exposed to air by accidental rupture of the hydride vessel. Another negative environmental impact could result from increased mining and metallurgic activity required to produce substantial amounts of metal hydrides.

2.3.4 Underground Storage of Hydrogen

Underground natural gas storage technology is over 60 years old, although most major developments have occurred during the last 30 years. Depleted gas or oil reservoirs have provided a time-tested environment for underground storage.

Hydrogen gas has been successfully stored in solution-mine salt caverns in England by Imperial Chemical Industries. This facility stores hydrogen at 5,200 kPa at a depth of 365 metres. Gaz de France operated a storage aquifer for storing hydrogen-rich (50 to 60 percent), low-Joule manufactured gas from 1956 to 1972. Helium has been stored by the U.S. Geological Survey in Bush Dome, near Amarillo, Texas, since 1960.

Two basic approaches to underground storage are:

- Porous media storage in which the gas occupies the naturally-occurring pore space between mineral grains or crystals in sandstone or porous carbonates

- Cavern storage in which the gas is contained in an excavated cavity in dense rock or solution-mine cavity in a salt bed

Storage in depleted oil and gas fields or in aquifers account for most underground storage facilities for natural gas. A natural gas storage field converted to hydrogen storage will store approximately one third of the natural gas energy equivalent.

The most recent study of underground hydrogen storage was completed by the Institute of Gas Technology for the U.S. Department of Energy in 1979.[24] This report investigated salt caverns, excavated caverns, aquifiers and depleted oil field storage. The general economic findings for these four classes of underground storage systems is presented in Table 2.4.

The world's first recorded underground storage project was undertaken in Canada in 1915 near Welland, Ontario. The number and type of underground storage facilities are shown in Figure 2.15.

Table 2.4 BASE-CASE ECONOMICS OF STORING HYDROGEN IN FOUR TYPES OF RESERVOIRS (24)

Item	Salt Cavern	Excavated Cavern	Aquifer	Depleted Field
Erected Plant Cost, \$$10^3$	16,400	50,000	31,900	6,660
Annual Throughput, 10^{12} Btu	1.44	2.03	1.7	0.976
Cost of Base Gas \$/10^6 Btu	6.00	6.00	6.00	6.00
Annual Operating Cost, \$$10^3$	350	425	1025	230
Construction Time, yr	3	3	3	3
Cost of Debt, %	10	10	10	10
Cost of Equity, %	15	15	15	15
Fraction Debt Financed	0.6	0.6	0.6	0.6
Lifetime for Economics, yr	27	27	27	27
Cost of Service, \$/10^6 Btu	3.03	5.27	6.59	4.47
Variation in Cost of Service, \$/10^6 Btu	(2.44-4.27)	(3.23-7.51)	(4.18-10.03)	(2.76-8.89)

(1979 U.S. Dollars)

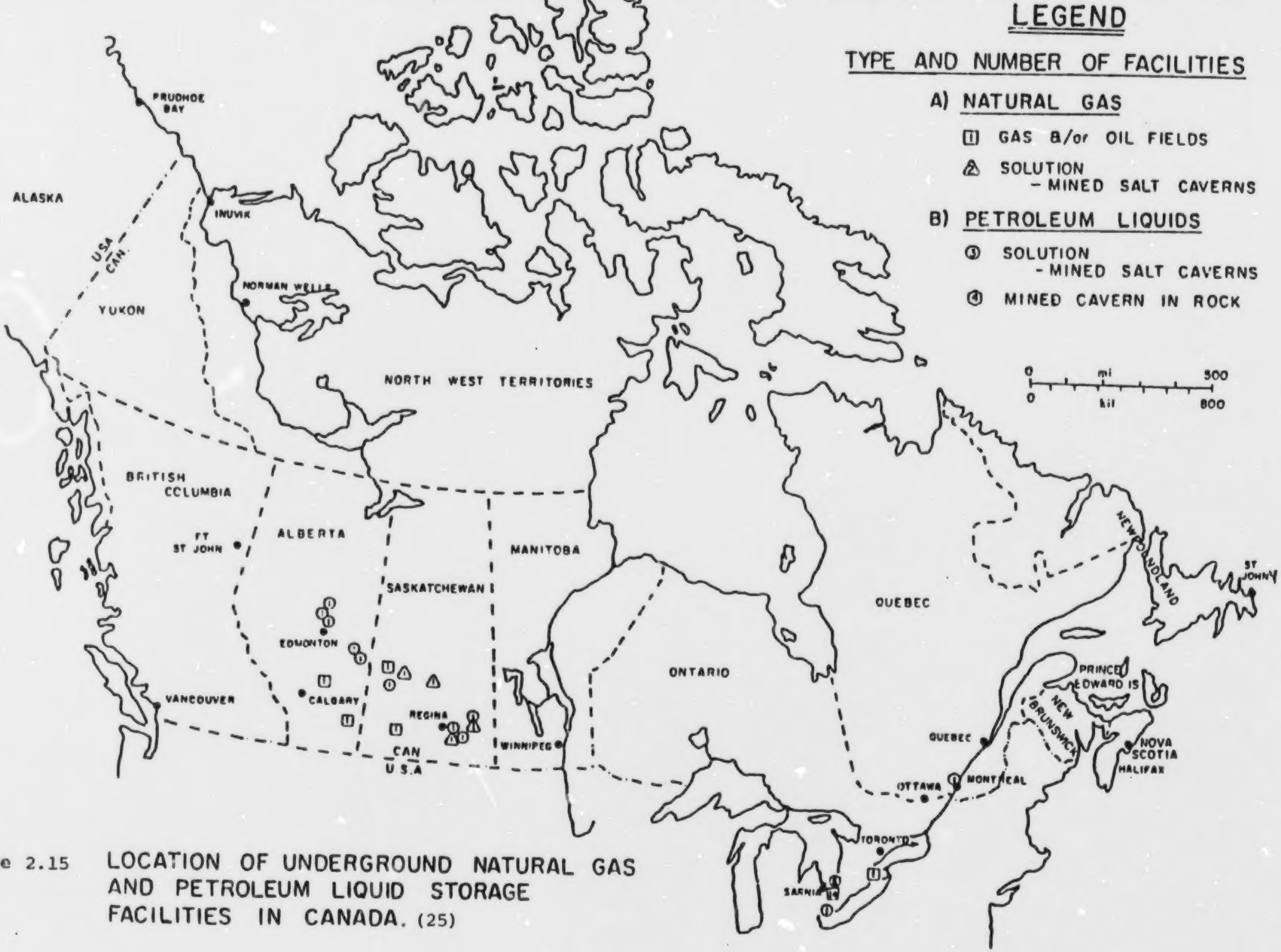

Figure 2.15 LOCATION OF UNDERGROUND NATURAL GAS AND PETROLEUM LIQUID STORAGE FACILITIES IN CANADA. (25)

The use of underground storage for the storage of hydrogen and natural gas mixtures is a transition option to the storage of hydrogen alone in the future.

2.3.5 Other Storage Technologies

In addition to the storage technologies already discussed, R&D efforts are underway in technologies such as chemical compound storage, as in the case of ammonia and methanol, organic working fluid storage and "microspheres" storage systems.

Chemical compound storage appears to have its most practical implementation in ammonia and methanol manufactured as energy carriers using hydrogen derived from non-fossil primary energy resources. These technologies are commercially available.

Organic fluid storage, where various organic compounds are used to store hydrogen, and glass "microspheres" storage technologies remain to prove their advantage over more technically mature alternative approaches to storage previously discussed.

3. HYDROGEN MARKETS

This chapter will identify current and potential hydrogen markets and estimate hydrogen demand for these markets. Two broad categories are used: present utilization in industry and potential use as a fuel.

Hydrogen is currently used in industry either as a feedstock or to improve the efficiency of a particular process. Hydrogen has inherent physical or chemical properties which make its use advantageous in these industrial applications. Several of these applications are expected to undergo substantial growth in hydrogen demand; others have only modest growth prospects. In all cases, hydrogen demand depends on the markets for the final product.

Utilizing hydrogen as a fuel is limited to the aerospace industry and specialty markets such as brazing and welding. Direct utilization as a fuel is currently restricted for technical and economic reasons. Although presently restricted, hydrogen proponents point to its abundance, favourable characteristics as an energy carrier, and increasing prices of conventional fuels as reasons why hydrogen should be considered as a potentially significant contributor to Canada's energy economy.

3.1 INDUSTRIAL MARKETS

Industrial markets for non-energy applications of hydrogen are dominated by the petro-chemical industry:

- petroleum refining
- ammonia production
- methanol production
- synthetic fuel production

As shown in Table 3.1, these four markets presently account for 15.04 Gm^3* of hydrogen use or 96 percent of total industrial demand. By the year 2025, hydrogen requirements in these sectors are forecast to increase to 34.62 Gm^3.

Other industrial applications of hydrogen consume about 0.51 Gm^3 at present. These applications include use in the following industries:

- metallurgy
- hydrogenation of food
- float glass production
- pharmaceuticals
- electronics
- utilities

Future hydrogen demand in these applications is forecast to grow to about 2.02 Gm^3 per year by the year 2025.

The balance of this section will discuss the characteristics of each market segment which make hydrogen an important feedstock. Trends in these markets as they affect hydrogen demand will be identified.

3.1.1 Petroleum Refining

Hydrogen is used in refineries to upgrade the heavier components of crude oil into the more valuable and lighter distillate products. The crude oil feedstock contains varying quantities of hydrogen depending on its quality and source. The distillate product contains hydrogen in proportion to the requirements of the end product. Any difference between hydrogen contained in the feedstock and total hydrogen contained in the refinery product slate must be supplied from sources external to the feedstock itself. As indicated in Table 3.2, hydrogen content

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* $Gm^3 = 10^9 m^3$

TABLE 3.1

CURRENT AND FORECAST HYDROGEN PRODUCTION IN CANADIAN INDUSTRY

	1980 (Gm^3/a)	2025 (Gm^3/a)
Petroleum Refining	4.90	7.50
Synfuels Production	1.43	11.40
Ammonia Production	5.50	11.00
Methanol Production	2.70	2.70*
Other	0.51	2.02
TOTAL	15.04	34.62

* excludes use of methanol in the transportation sector.

TABLE 3.2

HYDROGEN CONTENT OF CRUDE OIL FEEDSTOCKS AND REFINERY PRODUCTS (1980)

	Hydrogen Volume (000 m^3/m^3)
Crude Feedstock	
Synthetic	1.22
Light	1.33
Heavy	1.16
Products	
Motor Gasoline	1.11
Turbo	1.24
Diesel	1.35
Furnace Fuel	1.28
Fuel Oil	1.18
Ashphalt	1.10
Lubes	1.39
Other Specs	1.40
Chemical Feedstocks	1.21

Ontario Petroleum Association, Potential for the Utilization of Hydrogen in Ontario Refineries, prepared for the Ontario Hydrogen Task Force, Volume 4, September, 1981.

varies from 1 160 to 1 330 m^3 per m^3 of crude feedstock and from 1 100 to 1 400 m^3 per m^3 for the products.[31]

Hydrogen is produced and consumed at various stages of the refining process. In general, hydrogen consumption occurs "as required" with no storage beyond the amount held in intra-refinery pipelines.

Across the Canadian industry, most hydrogen is produced through the catalytic reforming of naptha streams, which remove hydrogen from the naptha hydrocarbons, to produce higher octane gasolines. Excess hydrogen becomes a gas stream used in other processing units or as a process fuel. Additional sources of hydrogen may be produced by steam reforming naptha or natural gas and the partial oxidation of the feedstock.

TABLE 3.3

ESTIMATED SOURCE OF CANADIAN HYDROGEN FOR REFINERY USE[32]

Catalytic Reforming	66%
Steam Reforming	33%
Partial Oxidation	1%
	100%

Hydrogen is consumed in the process of treating the feedstock to yield products of the required specification. Hydrotreating may be low or high in severity depending on the purpose for which hydrogen is used. Low severity processing is used to desulphurize the naptha feedstock (producing H_2S), remove nitrogen (producing NH_3) and selectively increase the hydrogen to carbon ratios of the various fractions. High severity hydrotreating or hydrocracking breaks up the "large molecule" hydrocarbons in the feedstock into the lighter, more valuable components used in gasoline, fuel oils and petrochemicals. Hydrocracking is carried out at high pressures and temperatures in the presence of hydrogen and catalysts. The reactions are used to convert sulphur to hydrogen sulphide and crack and add hydrogen to the heavy molecules. The process yields a higher quality material for further processing with less of the residuals, which are more difficult to process.

In terms of hydrotreating capacity as a percentage of crude oil capacity, hydro-desulphurization is utilized more extensively than hydrocracking. Although hydrocracking is small in proportion to the total, it is becoming more prevalent due to changes in the characteristics of crude feedstocks. Hydrocracking consumes roughly 4.5 times more hydrogen per m^3 of feedstock than hydro-desulphurization.[32]

	Hydrotreating as a % of Crude Oil Capacity	$m^3 H_2$ per m^3 feedstock
desulphurization	44.0%	36
hydrocracking	3.6%	160
others	2.5%	50

From a national perspective, Canadian refineries produce more hydrogen than is consumed in their operations. Production is estimated to be roughly 4.8 Gm^3 per year and consumption approximately 3.1 Gm^3 per year.

• desulphurization	-	2.1 Gm^3
• hydrocracking	-	0.8 Gm^3
• others	-	0.2 Gm^3
		3.1 Gm^3

Surplus hydrogen production is typically used as a process fuel. A small volume of hydrogen is sold on the merchant market after upgrading to a higher purity. While the industry as a whole produces surplus hydrogen, the individual refineries will be unique in their requirements. Processes and product slate vary across regions and among the refineries.

Hydrogen requirements in the Canadian refinery industry are expected to increase substantially over the next 40 to 50 years. At present, the industry is predominantly based on the availability of domestic and offshore light crude oil feedstocks. Several factors suggest that the industry is entering a period of transition to different feedstocks and process requirements.

- Most refineries are unable to convert residual distillation products (heavy fuel oil and asphaltenes) into higher grade fuels. Many of these products are exported to the United States for further processing. Refining these residuals in Canada will require expansion programs and new equipment at existing refineries.
- Reserves of light crude oil in conventional areas are declining and the prospects for utilizing heavy crudes from Saskatchewan and Alberta are improving. This source of crude requires upgrading to yield a product compatible to existing refinery capabilities.
- Synthetic crudes from tar sands or coal are incompatible with the capabilities of most facilities at high levels of processing requirements. Tar sands crude are currently blended at relatively low levels with higher quality crudes.

The Ontario Petroleum Association in its report to the Ontario Hydrogen Task Force projects a substantially reduced availability of light crude oil feedstocks by the year 2015 compared to today. As a percentage of total crude feedstock to Ontario refineries, light crude will decrease from 74 percent to 24 percent, synthetic and heavy crude will increase from 10 and 16 percent to 38 percent respectively.

As the feedstock becomes heavier, processing requires more hydrogen in higher severity hydrotreating processes, to counteract lower H_2:C ratios and the higher production rate of "residuals". Over the long term, it is anticipated that to maximize output, the heavier crudes and residuals will be treated and upgraded in hydrocracking facilities. To satisfy this requirement, hydrocrackers may represent 17 percent of crude oil capacity by 2025 compared to 3.6 percent in 1980.

Total hydrogen production is forecast to increase to 7.5 Gm^3 by 2025 compared to 4.9 Gm^3 in 1980. Hydrogen consumption will more than double to 7.0 Gm^3 by 2025. The industry will remain broadly self-sufficient over the period. Depending on the nature of the feedstock and the product slates required, refineries may be required to produce hydrogen from sources external to the feedstock. Predicting these demands is speculative as the exact nature of the future crude feedstock is uncertain and the required product slate past 2000 is difficult to specify.

The Ontario Petroleum Association[31] in its submission to the Ontario Hydrogen Energy Task Force forecasts between 1.6 and 3.1 Gm^3 of supplemental hydrogen may be required in Ontario by the year 2015 with sensitivities ranging from a surplus of 0.21 Gm^3 to a deficit of 6.2 Gm^3 per year. While there is uncertainty, a doubling of hydrogen production in Canadian refineries by the year 2025 appears reasonable, although it may be substantially more.

3.1.2 Synthetic Fuels

A potentially significant consumer of hydrogen is the synthetic fuels industry. Hydrogen may be used to improve the efficiency of hydrocarbon fuel production from unconventional reserves, such as heavy oil, tar sands bitumen and coal. Each of these resources requires upgrading to produce a product having a hydrogen : carbon ratio high enough for further processing in conventional refineries. In these applications, hydrogen will be an increasingly valuable feedstock in extending fossil fuel supplies.

While Canada has an abundance of both tar sands and coal, only two plants are currently in operation: Suncor and Syncrude tar sands plants in Alberta. These two facilities currently consume in the order of 1.50 and 2.83 Mm^3 of hydrogen per day respectively or 1.43 Gm^3 total per year.[32] The source of hydrogen in both cases is steam reformed natural gas.

Tar Sands

There are two options in upgrading tar sands bitumen to hydrogen : carbon ratios comparable to conventional light crudes:

- extracting carbon (coking)
- adding hydrogen (hydrotreating)

For each option there are a number of process alternatives, each requiring varying amounts of hydrogen.

Carbon extraction technologies are used by both the Suncor and Syncrude plants.

- delayed coking, as used by Suncor, heats process bitumen in fixed heaters to a cracking temperature. The bitumen is soaked in large cracking drums where coke and cracked gases are produced and recovered. The cracked products are further processed in downstream units to yield the crude oil product.

- fluid coking as used by Syncrude introduced bitumen directly to a fluidized bed reactor where cracking takes place. Vapours are recovered and fractionated into the desired product (crude) for further processing.

In both cases, coke is produced in significant quantities (e.g., three million tonnes per year at Syncrude). The coke may be stockpiled, combusted for process heat or gasified to produce a low quality gas containing hydrogen and carbon monoxide. Hydrogen requirements for processing are derived from the coker gas, reforming natural gas, or a combination of the two.

Alternative bitumen processing technologies, as yet unused in commercial facilities, minimize the production of coke by adding hydrogen to the bitumen. Hydrogen addition processes have superior oil yields with minimal by-products compared to the coking technologies. Bitumen is hydrogenated and cracked in one process step.

While hydrogen addition technologies are more expensive than the coking option, future tar sands projects are likely to see increased reliance on this option: superior yields are obtained and it removes the problem of disposing large quantities of coke.

The commercial prospects for tar sands upgrading is uncertain at present. The most recent forecasts by Energy, Mines and Resources predicts crude oil supply requirements of 93.1 million m^3 in 2001, of which 30 percent will be obtained by synthetic crude oil. This level of supply is expected to remain steady or increase slightly by 2025. Three additional tar sands plants, each producing 20 000 m^3 per day, will be required to satisfy this supply requirement. Upgrading through bitumen hydrogenation consumes roughly 320 m^3 of hydrogen for each m^3 of the crude product. On this basis, hydrogen consumption of 8.4 Gm^3/a is forecast for the year 2025.

Coal

As with tar sands, coal upgrading requires the hydrogen to carbon ratios of coal to be improved. Coal upgrading may produce synthetic natural gas or liquid fuels, depending on the processes used. No facilities of this kind are presently in place in Canada. A number of potential projects proposed for the 1990's have been cancelled or put on hold.

There are two primary coal conversion technologies which yield an energy product having a higher hydrogen content than the feedstock coal: gasification and liquefaction.

- a number of gasification processes convert coal to a synthesis gas composed primarily of hydrogen and carbon monoxide. The synthesis gas may be purified to produce a high purity hydrogen product or a synthetic natural gas.
- liquefaction processes may indirectly or directly produce liquid fuels. Indirect methods convert synthesis gas to liquid fuels (e.g., gasoline) in the presence of highly selective catalysts. Direct liquefaction processes, hydrogenate the coal to produce a synthetic crude.

Both options require significant volumes of hydrogen. Coal to synthetic natural gas requires roughly 1.3 m^3 of hydrogen per m^3 of gas produced and hydrogenation requires roughly 1 290 m^3 of hydrogen per m^3 of synthetic crude produced.[32] For each relatively small scale coal liquefaction plant producing 3 200 m^3 per day of synthetic crude, roughly 1.5 Gm^3 of hydrogen per year would be required. Total capacity by the year 2025 may be the equivalent of two such plants or 3.0 Gm^3 of hydrogen.

3.1.3 Ammonia Production

The largest producer and consumer of hydrogen at present is the ammonia industry. Ammonia is used as feedstock in a number of other downstream industries, including the production of fertilizers, textile fibres, nitrates, resins and explosives.

Hydrogen is produced by steam reforming natural gas and consumed by introducing three parts hydrogen to one part nitrogen into the ammonia synthesis train. The primary processing steps are shown in Figure 3.1. In the order of 2 071 m^3 of hydrogen is required per tonne of ammonia produced.[32]

Total reported anhydrous ammonia production in 1981 was 2.65 million metric tonnes, representing a 100 percent utilization of existing production capacity. Hydrogen requirements were approximately 5.5 Gm^3.

Ammonia production has grown significantly over the past 20 years to serve the domestic fertilizer industry and for export markets, primarily to the United States.

CANADIAN ANHYDROUS AMMONIA PRODUCTION

(tonnes)

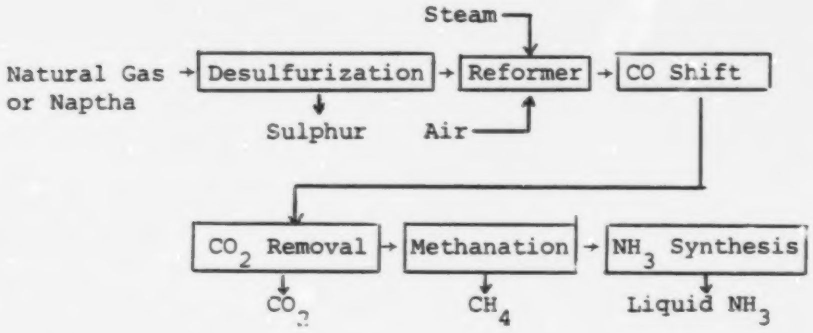
1960	473,508
1965	737,363
1970	1,344,956
1975	1,336,373
1980	2,555,582

Present production capacity is approximately 2.55 million tonnes/year. By 1984, an additional three plants with 1.25 million tonnes of capacity are anticipated to be on line, bringing capacity to 3.91 million tonnes. Export markets to the United States are expected to remain strong for the balance of the decade, with increased competition from Mexico and other offshore suppliers thereafter. The domestic fertilizer industry is projected by the Canadian Fertilizer Association to sustain at least a three to four percent annual growth over the remainder of this decade and probably beyond.

On this basis, ammonia production in the year 2025 is projected to be roughly 5.3 million tonnes, requiring in the order of 11.0 Gm^3/a hydrogen.

FIGURE 3.1

NH_3 PRODUCTION BY STEAM REFORMING



3.1.4 Methanol Production

Methanol is another important industrial chemical which requires large quantities of hydrogen to produce. Methanol is used as a feedstock in a number of industrial processes. Products which rely on methanol include:

- formaldehyde resins
- acetic acid
- solvents
- wood laminates
- methyl methacrylate
- methyl chloride
- methyl bromide
- methylamine

The production of methanol is similar to the process used for ammonia manufacturing. Natural gas is reformed to produce hydrogen and carbon monoxide and shifted to yield a ratio of approximately two parts hydrogen to one part carbon monoxide, as required to produce methanol. The synthesis gas is passed over highly selective catalysts to produce a methanol and water mixture. This mixture is transferred to a still where the water is separated and the methanol distilled to the desired purity. Each tonne of methanol produced requires approximately 1 495 m^3 of hydrogen.[32]

The methanol industry has expanded its capacity dramatically over the past several years, from 0.41 to 1.8 million tonnes per year. Most of this increased capacity has been established for export markets, primarily in the U.S. and Pacific Rim countries. Domestic markets account for only 275 000 tonnes per year.

Over the short term, many of these traditionally secure export markets may be threatened by an emerging global methanol surplus as several other countries bring new methanol capacity on line. Some industry observers believe that surplus could be as high as 3.5 million tonnes by the year 1985.

While a global methanol surplus does not rule out the possibility of further investment in domestic capacity, it is unlikely that such investment will occur over the short to medium term based on existing markets. Hydrogen demand is, therefore, forecast to remain constant at the current level of 2.7 Gm^3/a.

A potentially significant new market which would affect this conclusion is the use of methanol as a transportation fuel. Methanol may be used as a blend with gasoline or neat. The potential demand for methanol, if either of these options becomes widespread, is enormous. As a fuel, the 1.5 million tonnes of methanol capacity, surplus to domestic demand, represents the equivalent of only five percent of gasoline used in the transportation sector. The extent to which methanol will play a significant role as a transportation fuel is unclear at present. All of the methanol producers are seriously evaluating the opportunity, however.

A significant methanol fuel market may also encourage the use of alternative feedstocks to natural gas in producing the required hydrogen. Gasification of coal, lignite, peat or biomass are all potential feedstocks.

3.1.5 Other Hydrogen Consumers

A number of other industries produce or consume hydrogen in their product processing. Consumption is much smaller in these industries compared to the primary producers and consumers in the refining and chemicals industries. Data on hydrogen consumption for many of these industries is limited, due to proprietary technologies or restricted production information. Several industries for which information on hydrogen requirements is available or can be inferred are:

- glass manufacture

- oil hydrogenation
- metallurgy
- power generator cooling
- pharmaceuticals
- electronics

Glass Production

All sheet glass produced in Canada is produced via the "float glass" process which casts the glass on a molten bed of metal to produce a smooth product. These molten beds are highly reactive and must have an oxygen free furnace atmosphere. The oven atmosphere consists of nitrogen and small amounts (from four to ten percent) of hydrogen. The purpose of introducing hydrogen is to scavange or react with any trace amounts of oxygen. Other minor uses of hydrogen in the glass industry include the use of oxy-hydrogen torches in glass cutting.

A survey of float glass producers indicates total hydrogen consumption of approximately 1.0 Mm^3 per year based on the number of float glass ovens in operation.

Foods

Edible organic oils and fats are routinely treated with hydrogen in a hydrogenation process. The major advantages of hydrogenated products are to:

- retard the tendency of the oil to oxidize and turn rancid
- achieve the desired consistency by producing a solid fat such as margarine and shortening instead of a liquid oil
- improve odour and colour

Inedible oils and greases are also hydrogenated to produce soaps and animal feeds.

Depending on the oil to be processed, hydrogen demand varies from 0.032 m^3 to 0.04 m^3 per kilogram of the oil or fat produced. Total hydrogen consumption by the nine oil refiners in Canada is approximately 11.7 Mm^3 per year. Major edible oil producers have on-site hydrogen generating facilities: producing hydrogen either by steam reforming natural gas or through electrolysis. Roughly 20 percent of hydrogen requirements is purchased on the merchant market.

Metallurgy

The primary applications of hydrogen in the metallurgical industry are in the direct reduction of iron ores and the production of non-ferrous metals (e.g., copper, nickel, zinc) from sulphide ores. Small amounts (approximately 24 million m^3 in Ontario) are also used in heat treating and sintering atmospheres, welding, copper brazing and uranium alloy production.

Current consumption from all applications is estimated to be roughly 0.5 Gm^3 per year. The application showing the greatest long term increase in the metallurgical industry is in the direct reduction of iron ore.

At present, the reduction of iron ores to metallic iron is primarily accomplished in blast furnaces. Hydrogen is used indirectly. Steam is injected into the hearth of the furnace along with the hot air blast where the water vapour reacts with the carbon in the coke at high temperatures to form hydrogen gas and carbon monoxide. These gases react with the iron oxides to produce iron, water vapour, carbon dioxide, carbon monoxide and sulphur compounds.

In recent years, the development of gas based direct reduction processes have been prompted by technology improvements and changes in the production economics of blast furnace technologies. Direct reduction processes do not melt the iron product as occurs in the blast furnaces. Rather, the iron product remains as a pellet similar to the raw material. The reducing agents which convert the iron oxides into iron are carbon monoxide, hydrogen, or a mixture of the two. Hydrogen is the faster reducing agent of the two.

As most of the big iron and steel producers already have large blast furnace capacities, the application of direct reduction processes will be limited to new facilities. The most immediate prospect is the development and expansion of the Midrex direct iron ore reduction plant at Contracoeur, Quebec, by Sidbec-Dosco. The source of hydrogen at this plant will be from the steam reforming of natural gas. Hydrogen consumption for this process is estimated to be 624 m^3 per tonne of iron ore produced.[32] Production of sponge iron by the Midrex process in Quebec is projected to be in the order of 1.95 million tonnes by 2025. Hydrogen demand will be roughly 1.2 Gm^3 at this level of production.

Total hydrogen consumption in all ferrous and non-ferrous metallurgical processes is estimated to be roughly 2.0 Gm^3 by the year 2025.

Power Generator Cooling

Electric utilities require hydrogen as a coolant for large generators, motors and frequency exchangers. Hydrogen is circulated through heat exchangers in the shell of the generator to cool the rotor and is circulated through the stator windings. Although designed as a closed recirculating system, hydrogen must be replaced periodically due to equipment purging and gaseous diffusion.

Ontario Hydro reports consumption of 57 000 m^3 of hydrogen per year for its installed capacity of 24 700 MW or roughly 23.08 m^3/a/MW. Assuming the same rate across the total Canadian installed capacity of 83 300 MW, hydrogen consumption is estimated to be 1.92 Mm^3/a.

By 1990, an additional 34 600 MW of domestic capacity is projected, based on projects underway or at the planning stages. Forecasting capacity beyond 1990 is subject to significant uncertainty. A total of 4.0 Mm^3/a of hydrogen is assumed for power generator cooling in 2025.

Other

Two other minor users of hydrogen for which information is available are in the manufacture of pharmaceuticals and in the electronics industry.

A number of pharmaceutical products utilize hydrogen. An example is sorbitol. Sorbitol is produced by catalytic hydrogenation of dextrose. Sorbitol is more compatible to the human digestive system than dextrose. Hydrogen requirements are estimated to be only 190 000 m^3 per year.

A survey of semi-conductor manufacturers in the Ottawa area revealed a minor but important use of hydrogen as an oxygen scavenger and as a brazing fuel for semi-conductor products. Total consumption is approximately 35 000 m^3 per year.

3.2 HYDROGEN FUEL MARKETS

Except for the small merchant hydrogen market, the hydrogen system presently used in industry is essentially a two step process: production and use. The nature of the applications and the source of hydrogen make other requirements such as transmission, storage and distribution largely unnecessary. Utilizing hydrogen directly as a fuel, however, will require that these aspects be incorporated into the hydrogen fuel system. Depending on the application, the hydrogen fuel system will more closely resemble the energy concept illustrated in Figure 2.1 in the previous chapter, and utilize more fully the technologies which must be in place to support it.

In theory, the hydrogen fuel market is limited only by the demand for energy in any given time period; hydrogen would form the basis for society's energy transactions. There is general agreement that this ultimate hydrogen economy will be possible only in the far distant future, if ever. The emergence of hydrogen as a fuel will be evolutionary; hydrogen will find market niches when the energy options in any particular market segment yield to the advantages of hydrogen over other competitive fuels. Over time, hydrogen may penetrate each of the industrial, commercial, residential and transportation fuel markets. At such a time, the possibility of a hydrogen energy economy would be a practical possibility.

This section describes a feasible hydrogen fuel system for each of several hydrogen fuel market applications. The technological requirements vary with the market category considered. These requirements are assessed in a preliminary way. Details on the environmental implications of these systems are provided in chapter 4. The hydrogen systems to be reviewed are:

- air transportation
- rail transportation
- road vehicles
- supplements to natural gas
- electricity storage
- replacing natural gas in the residential, commercial and industrial sectors
- universal hydrogen fuel system

We have reviewed the potential and probable market for these applications based on recent and, where possible, forecast energy use statistics for the year 2025. The results are shown in Table 3.4. In aggregate, the potential market, if hydrogen alone was used for each application, is between 1 938.2 to 3 388.6 PJ of energy. This is equivalent to 160.1 to 279.9 Gm^3 of hydrogen. While the potential market is large, the probable hydrogen market for 2025 is considerably smaller. After considering the various constraints faced by each application, the probable hydrogen market is forecast to be 0.58 Gm^3.

TABLE 3.4

POTENTIAL AND PROBABLE MARKET FOR HYDROGEN IN FUEL APPLICATIONS IN 2025

	Potential Market (Gm^3/a)	Probable Market (Gm^3/a)
Aircraft	12.4 - 16.5	0.25
Rail Transportation	7.4	0.12
Road Transportation	107.4	0.21
Natural Gas Supplementing	4.1	0
Electricity Storage	24.7	0
Natural Gas Replacement	123.9	0
	160.1 - 279.9*	0.58

* range indicates either natural gas supplementing or replacement

The applications where hydrogen penetration can be expected to occur are for aircraft (0.25 Gm^3), rail transportation (0.12 Gm^3) and road transportation (0.21 Gm^3). This level of demand would require in the order of 350 MWe of generating capacity.

As discussed in the next section, any forecast of hydrogen use as a fuel is subject to considerable uncertainty. On the basis of the analysis summarized above, however, it is highly unlikely that hydrogen will be a significant fuel by the year 2025.

3.2.1 Factors Influencing Hydrogen Penetration

Most hydrogen energy scenarios assume that changing energy economics will encourage the substitution of hydrogen for conventional fuels. Forecasting hydrogen energy demands is difficult because the energy system is complex, poorly understood and dynamic. There is great uncertainty associated with any forecast, particularly so for the introduction of a new fuel such as hydrogen, which has unproven economics and which relies on technology still under development.

A simplified model of the Canadian energy system would consist of six interacting components: energy services, the supply mix, energy technologies, geological reserves, politics and economics. Each of these is briefly discussed to indicate its impact on the development of hydrogen fuel systems and areas of uncertainty.

Energy services, supply mix and technologies are interdependent factors in that they interact strongly and a change in any one results in a change in the energy use pattern. It is difficult, if not impossible, to project what energy using services will be desired over the next fifty years. The supply mix is difficult to determine because it is based on the economics of energy sources and technologies, geological reserves and political decisions (e.g., the current off-oil programs of federal and provincial governments).

Energy services are satisfied by energy supplies in combination with specific technologies which allow conversion of the raw energy into useful services such as heat, light, and motive power. Hydrogen energy technologies are at an early stage of development. As indicated in chapter 3, few technologies have yet reached commercial application, most remain at the conceptual or prototype stages. For all applications, considerable technological development is a prerequisite to commercialization. The experience with several other technologies suggests that problems are often more difficult to solve than originally expected. Alternatively, the time frame over which hydrogen technologies will be introduced is sufficiently long that new technologies with entirely different operating systems may be developed, making assessments undertaken now largely obsolete.

The understanding of petroleum geology is not sufficiently advanced to permit accurate assessments of reserves or resources. This adds considerable uncertainty to estimates of the time and rate of exhaustion and hence the costs of fossil fuels. In addition, reserve estimates are made assuming specific technologies. If new technologies for exploiting previously unavailable resources are available, reserve estimates may be increased.

As the oil price shocks of 1973 and 1979 made clear, the energy system is dependent on many decision makers, both domestic and foreign. The supply mix and energy economics can be expected to be increasingly determined by political considerations. Naturally, it is impossible to predict political factors with any confidence.

Economics also play an important role in influencing the supply mix, energy services and hence, energy use. Factors affecting economics include geological reserves, energy technologies and politics. As discussed, each of these can be assessed with little confidence.

The economics of electrolytic hydrogen supply are affected not only by the availability and price of fossil fuels, but also the cost of electricity. Widespread use of electrolytic hydrogen as a fuel is contingent upon electricity being considerably cheaper than fossil fuels so that even after accounting for the costs associated with electrolysis, hydrogen is cheaper than fossil fuels on a useable unit energy basis.

The economics of hydrogen energy systems depend not only on the costs of the hydrogen relative to competing fuels, but also the costs of hydrogen distribution and utilization technologies relative to the technologies for other fuels. Because these technologies are immature, their economics cannot be accurately estimated. The experience of other technologies indicates that cost estimating procedures are poor even for mature technologies; those for new technologies for which the components cannot even be specified with confidence must be considered suspect.

Ironically, it is usually the most uncertain aspect of hydrogen systems on which they are projected: their economics. A preferable approach would be to evaluate them on the basis not only of projected economics but also on their technical feasibility, theoretical energy efficiency and compatibility with social and environmental system goals.

With these comments in mind, the following hydrogen fuel systems are proposed as the most practical contenders for the various fuel applications.

3.2.2 Air Transportation

Hydrogen has been suggested as a fuel for aircraft and a considerable amount of work has already been accomplished to design both aircraft and fuelling systems. No aircraft have yet been built to fly on hydrogen.

Hydrogen has some significant advantages as an aircraft fuel. For example, reducing the mass to be carried is an important consideration of aircraft operators and hydrogen has a mass energy density more than two and one half times as high as conventional jet fuel. This leads to:

- reduced fuel consumption
- a reduction in the required runway length
- reduced wear on the runways
- quieter take-offs

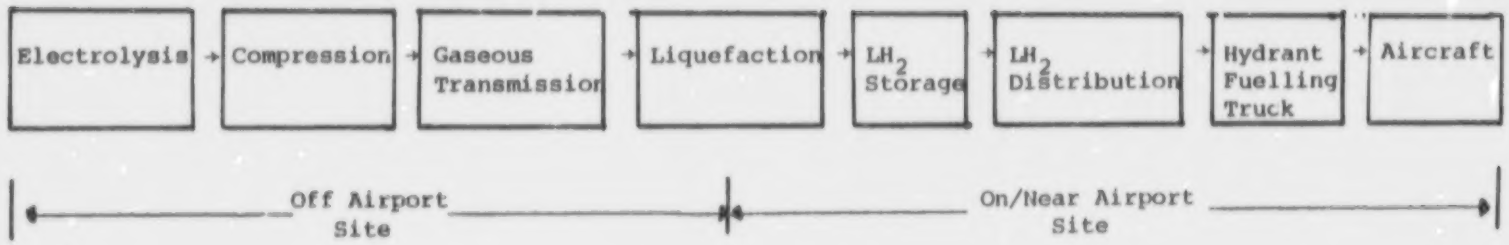
Figure 3.2 presents a schematic of a possible hydrogen fuelled aircraft system. Gaseous hydrogen is supplied by pipe to a liquefaction plant at or near the airport. Liquefied hydrogen (LH_2) is stored near the liquefaction plant, most probably in large, above ground spherical containers. From the point of storage, LH_2 is piped underground in a cryogenic pipe to the aircraft loading gate. A gaseous hydrogen pipe runs parallel to the LH_2 pipe to carry boil-off gases back to the liquefaction plant. At the aircraft departure gate, a hydrant fuelling truck fuels the hydrogen aircraft. Aircraft using LH_2 will be specially designed; retrofit applications are very improbable.

Possible permutations of this system include electrolysis and liquefaction on site, or shipping LH_2 to the airport directly in rail or truck bulk carriers, rather than having liquefaction facilities on the site. The latter is likely in the early stages of development, when an extensive gaseous hydrogen system is not in place and when the LH_2 demand is too small to justify a liquefaction plant.

The market for hydrogen in the aircraft industry is quite large. In 1979, airlines used 137 PJ of energy. By 2025, this market may be as much as two times as large, even after accounting for aircraft fuel efficiency improvements. Since hydrogen aircraft are expected to be

FIGURE 3.2

THE HYDROGEN AIRCRAFT FUEL SYSTEM



about one third more efficient, the potential energy market for hydrogen is 150 PJ to 200 PJ, or the equivalent of 12.4 to 16.5 Gm^3 of hydrogen per year.

Although the aircraft industry has a relatively simple infrastructure (relative to energy use) and is therefore one of the preferred targets for hydrogen as a fuel, the "probable" market is quite small. One reason for this is that although the infrastructure may be relatively small, it is geographically dispersed; hydrogen facilities must be available at both source and destination. Another is the nature of the growth in the market.

The rate of growth is likely to decrease over time. This suggests that the new markets opening up after hydrogen is available will be quite small. Even in these new markets, hydrogen will face stiff competition from conventional and synthetic jet fuel, particularly when these fuels are used in the newest, most efficient aircraft.

It has been proposed that, as a first step in the development of a hydrogen aircraft system, a network of cities install hydrogen fuelling facilities at airports on a demonstration basis. Mirabel and Malton have been proposed for the Canadian leg of the network which would also include Frankfurt and Los Angeles. Of these two, Mirabel is probably most attractive because of its greater available capacity and its separation from built-up residential areas. Assuming that hydrogen aircraft are still in the demonstration stage in 2025, the probable energy market is about 3.0 PJ per year (2 TJ per fuelling x 4 fuellings per day x 365 days per year) or 0.25 Gm^3 of hydrogen per year.

3.2.3 Rail Transportation

Liquid hydrogen may be a suitable fuel for some rail transportation applications. The relatively low volume energy density of hydrogen poses no real problem for rail transportation and hydrogen is well suited for use in fuel cells to produce electricity on board the locomotives. As for air transport, the infrastructure requirements are relatively small relative to the potential demand. Unlike the hydrogen air system, a hydrogen rail system could be introduced into a single geographic area, especially if it was one with a high fuel demand, such as a commuter rail line.

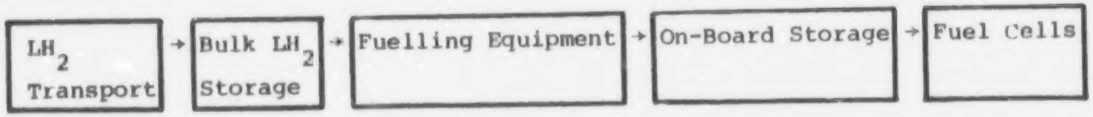
Figure 3.3 presents a hydrogen fuelled rail system possibility. Liquid hydrogen is produced off-site and transported to the rail yards where it is stored. Trains carry the LH_2 in a separate vacuum insulated tender behind the locomotive. As is currently the case, the locomotives use the fuel (in this case hydrogen) to generate electricity onboard to drive electric motors. Theoretically, fuel cells are very efficient at generating electricity from hydrogen, and thus they have been assumed in the system presented. Other locomotive types including diesels, internal combustion engines and turbines, could also be converted to hydrogen.

In 1979, Canadian railways used 93 PJ of energy, or the equivalent of 7.4 Gm^3 of hydrogen. Without regard to how this demand might change over the next 40 years, the market for hydrogen is likely to be quite small. Railways are conservative, the technology for using hydrogen has yet to be developed and demonstrated and infrastructure requirements will probably restrict the penetration of hydrogen. One of the preferred applications for the introduction of hydrogen into the rail system is commuter rail: return trip distances are relatively short, allowing one refuelling area rather than several. Hydrogen could be introduced incrementally with minimal infrastructure requirements (especially in comparison to those associated with railway electrification).

In 1980, the Ontario GO rail system used about 0.25 PJ of energy. The Ontario Ministry of Energy expects this demand to grow to about 0.3 PJ by 2000. A probable market of about 1.5 PJ of energy or 0.12 Gm^3 of

FIGURE 3.3

A HYDROGEN FUELLED RAIL SYSTEM



hydrogen in Canadian railroads is projected for 2025, representing less than two percent of the potential market.

3.2.4 Road Vehicles

Road vehicles use very large amounts of energy; in 1979, more than 1 300 PJ of energy was consumed by road vehicles in Canada, mostly by automobiles. In view of this large demand, and the near total dependence on oil (the most critical energy type), much of the consideration of new fuels, including hydrogen, is for applications in road vehicles.

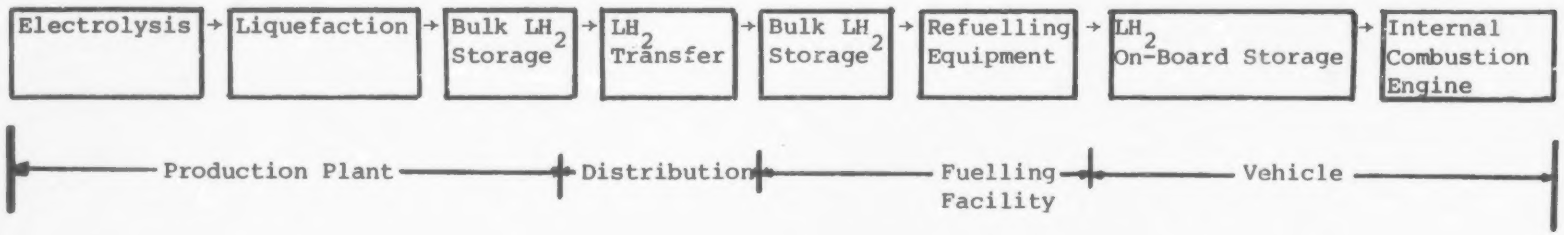
Significant barriers exist to the large scale introduction of hydrogen into road vehicle applications. The infrastructure requirements are extensive, particularly for private automobiles, whose owners are unlikely to look favourably on any fuel which is not readily available throughout not only their local area but also all probable trip destinations. As with other possible hydrogen applications, the technology is quite nascent. There is some experience with conversion of existing vehicles (primarily automobiles) to run on hydrogen. Converted vehicles have experienced significant fundamental technical problems, however. Successful penetration of hydrogen into the road vehicle market will require specifically designed vehicles for using hydrogen.

A sketch of a reasonable system for hydrogen fuelled road vehicles is presented in Figure 3.4. Liquid hydrogen is produced electrolytically at centralized locations, the hydrogen is liquefied and stored in bulk quantities. From the production plant, the liquid hydrogen is shipped via rail or, more likely, truck, to refuelling facilities. On-board storage of hydrogen would be as a liquid in a cryogenic tank.

Liquid hydrogen has a number of advantages over gaseous hydrogen. Shipment to fuelling facilities by truck is easier, eliminating the need for an extensive pipe distribution system. Although liquid hydrogen has

FIGURE 3.4

THE HYDROGEN ROAD VEHICLE SYSTEM



a lower volume energy density than gasoline, expected improvements in vehicle fuel economy will mean that fuel requirements will be roughly the same as today.

On-board storage of liquid hydrogen also has some advantages. Although it is not considered as safe as metal hydride storage, LH_2 storage does not suffer from the weight problems associated with storage of gaseous hydrogen, either under compression or in hydrides. Gaseous storage would greatly reduce the vehicle range, restricting the use of hydrogen to urban applications. However, although urban duty cycles typically are tolerant of small ranges, the stop-start cycle and other urban performance requirements are generally not compatible with the low power to weight ratio that is associated with hydrides. Furthermore, the limited vehicle range of hydride vehicles will mean that distinct hydrogen fuel systems will be required for urban and intercity applications, a situation which is probably unacceptable to the operators in the largest single sub-sector: private automobiles.

A disadvantage of LH_2 is the overall losses from the system as it moves through the distribution channel. Between 30 to 70 percent can be expected to be lost from the point of production to vehicle storage, based on past experience.

Energy demand for road transportation is likely to be about the same in 2000 as it is now because of improvements in fuel economy offsetting increasing distances travelled and mass transported. By 2025, a modest decline in use might reasonably be expected. However, growth or decline in energy demand is not uniform across all transportation modes. In general, energy use by automobiles declines as a result of improving vehicle fuel economy, whereas energy use by trucks and buses grows, due to the greater market shares these sectors will capture. Within each mode, hydrogen will face stiff competition from other fuels (including propane, natural gas, methanol and electricity), and from conservation.

Over the foreseeable future, the preferred applications of hydrogen in road transport are inter-city trucks and buses. The attractions of these modes include:

- relatively high fuel use (allowing more rapid recovery of incremental vehicle costs)
- well defined routes with minimal infrastructure requirements
- these modes usually have separate fuelling facilities
- there is a high degree of customisation in manufacturing these vehicles

Use of hydrogen as a fuel for inter-city trucks and buses has yet to be demonstrated, and it is improbable that much more than 2.5 PJ of the road transportation energy use in the year 2025 will be provided by hydrogen. This is equivalent to 0.21 Gm^3 of hydrogen and less than 0.2 percent of the potential transportation market.

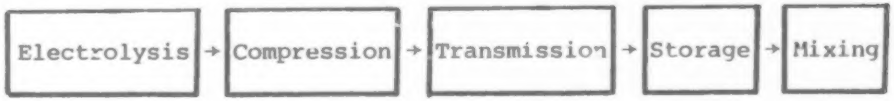
3.2.5 Natural Gas Supplementing

Natural gas supplies may be extended by adding hydrogen to them before use. It is possible to add 10 to 15 percent hydrogen (by volume) to natural gas without having to make changes to distribution systems, end-use equipment, meters, pumps and other equipment. Since hydrogen has a lower volume energy density than natural gas, the natural gas/hydrogen mixture would contain only three to five percent of its energy in the hydrogen.

A natural gas supplementing system is presented in Figure 3.5. As with other systems, hydrogen is produced by electrolysis; if fossil fuels were available for hydrogen production it would be more efficient and convenient to use them directly or convert them into a convenient hydrocarbon. Unlike the other systems, this system is based on compressed gaseous hydrogen rather than liquid hydrogen. Liquefaction is an expensive process and is only used where there are clear advantages to having

FIGURE 3.5

HYDROGEN AS A NATURAL GAS SUPPLEMENT



the hydrogen transported or stored as a liquid. The hydrogen would be compressed to about 5 000 kPa and transmitted via high pressure pipeline. Storage will be required, as hydrogen production will likely occur during off-peak electric times and a buffer is needed to ensure that a constant mixture is maintained. It is probable that such a system would be located near demand centres as electricity is usually readily available at these sites and transmission costs can be reduced.

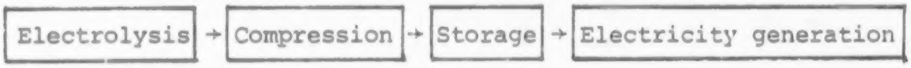
Storage of hydrogen as a compressed gas may not be reasonable at this scale, unless suitable aquifers or salt caverns are available. This system may be well suited to hydride storage since the low power to weight ratio is not a concern, and hydride storage is safest, a particular concern at demand centres.

In 1979, roughly 1 500 PJ of natural gas was consumed in all sectors. A 10 percent by volume supplement of hydrogen would amount to 50 PJ of energy, after correcting for its lower energy density. This is equivalent to 4.1 Gm^3 of hydrogen. There are some significant barriers to the use of hydrogen to extend natural gas supplies, however. Over the near term, natural gas appears to be readily available at reasonable cost. If hydrogen is available at a cost per unit energy that is lower than natural gas, then presumably electricity will also be less expensive than natural gas. Under these conditions, electricity may be the preferred energy source. Supplementing natural gas during a transitional period is probable only if the quantity of hydrogen required is a relatively small component of total hydrogen production so that the facilities producing hydrogen for this application can direct their hydrogen to other markets as the use of natural gas (supplemented with hydrogen) declines. This situation does not seem likely by 2025.

3.2.6 Electricity Storage

One of the disadvantages of electricity and one of the advantages of hydrogen is their respective ability to be stored. Electricity must be used as produced; storage is prohibitively expensive. Hydrogen, however, can be produced when it is convenient and stored until needed. Since hydrogen can be produced using electricity and electricity can be generated from hydrogen, hydrogen might be considered as a mechanism for "storing" electricity. Such a scheme is presented in Figure 3.6.

Figure 3.6 - Electricity "Storage" Using Hydrogen



The concept is quite simple. Hydrogen is produced using electrolysis when electricity demand is low ("off-peak"), is compressed and stored. As for gas supplementing, the preferred storage technology is probably hydrides. When electricity demands are at their peak, hydrogen would be used to generate electricity, probably using a fuel cell. This would have the effect of "levelling" the load on the utility system.

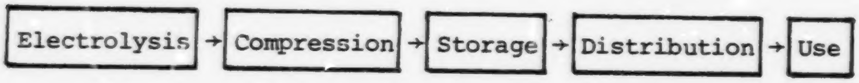
To give an indication of the potential use of hydrogen for peaking purposes, roughly 30 percent of the 1 000 PJ of energy used for electricity generation in 1979 was consumed for peaking requirements. This is the equivalent of 24.7 Gm^3 of hydrogen.

There are, however, problems with the concept. Conversion of electricity to hydrogen and then back to electricity is expensive in terms of both energy and money. Typical efficiencies for electrolysis and fuel cells are 82 and 53 percent respectively, giving an overall efficiency of about 43 percent (electricity to electricity). Looking only at energy operating costs and assuming an efficiency of 35 percent for conventional peaking facilities (primary energy to electricity), fuel costs alone would have to be over 80 percent of the cost of base load electricity. If capital costs are included, the costs per GJ of conventional peaking fuels in primary form would have to be greater than the cost of base load electricity, since capital costs for an electricity storage and hydrogen peaking system would be much higher than capital costs for a conventional peaking system alone. At these fuel price levels, the demand for hydrogen as a fuel or feedstock is likely to be so high that it will be both cheaper and thermodynamically more efficient to curtail hydrogen production to maintain a level demand curve rather than using hydrogen fuelled peaking facilities to follcw a fluctuating demand curve. Consequently, the demand for hydrogen for electricity storage will probably be small.

3.2.7 Hydrogen in the Residential, Commerical and Industrial Sectors

Natural gas is used in the residential, commercial and industrial sectors primarily for generating heat: space heat, water heat and process heat. All of these services could be provided by hydrogen, via a system similar (from the user's perspective) to the natural gas system. Such a system is presented in Figure 3.7.

Figure 3.7 - Hydrogen in the Residential, Commercial and Industrial Sectors



With sufficient demand in a fairly localized area, hydrogen could be produced, stored and distributed at the community level. Production is by water electrolysis, the hydrogen is compressed and stored in hydrides, and then distributed by pipe, much like natural gas. Hydrogen furnaces and appliances are designed for the specific properties of hydrogen. These could include ventless, flametype combustors which would be more efficient than conventional vented combustors. Appliances use a catalytic system which requires no primary air supply and which has a steel wool catalyst covering the gas port to spread the flame and distribute the heat.

It is unlikely that an existing natural gas system would be retrofitted to use hydrogen. More probable is the introduction of such a system into a new development. In the residential and commercial sector, such a system would face considerable competition from direct electricity use. In the case of residences, at the fuel prices required to make hydrogen attractive, economics suggest efficiency levels so high that hydrogen would have to be much cheaper than electricity just to justify the infrastructure costs. In the industrial sector, if the hydrogen infrastructure is already in place for other uses, then hydrogen heating may be attractive. Overall, the market for hydrogen for generating space, water and process heat over the foreseeable future is negligible.

3.2.8 A Universal Hydrogen Fuel System

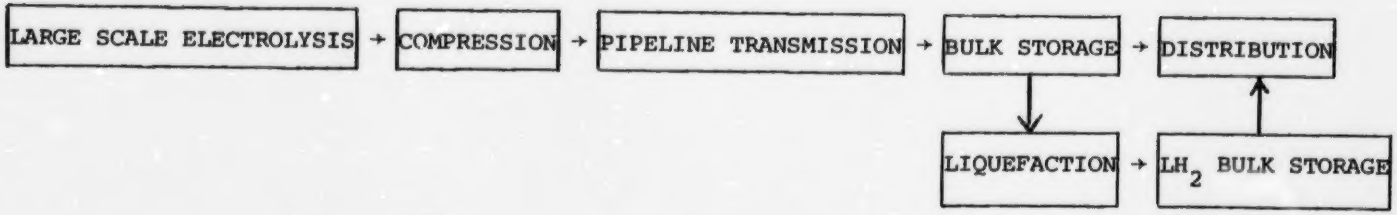
As the systems considered above suggest, hydrogen could be the basis of a universal fuel system, acting as the energy medium for the transportation sector; the residential, commercial and industrial sectors; and even for electricity generation (as a part of electricity storage). Each of these systems has been described separately, but at some point it becomes logical for the various systems (both sectorally and geographically) to interconnect to take advantage of economies of scale (where they exist) and to provide redundancy (and hence stability).

The "utility" side of such a system is presented in Figure 3.8. This system includes a large scale electrolysis unit (probably using a dedicated electric power plant), large scale compression and liquefaction facilities, large scale bulk storage and transport facilities.

Hydrogen to be used in feedstock and stationary fuel applications is produced, stored, transmitted and used as a high pressure gas. In some cases, such as remote hydro plants, lengthy high pressure (e.g., 5 mPa) pipelines might be used. Since electricity is much more expensive to

FIGURE 3.8

THE UNIVERSAL HYDROGEN SYSTEM



transmit than hydrogen over long distances, all power might be converted into hydrogen and then the hydrogen used to generate electricity near the demand centre: an extension of the electricity storage concept. The volume of hydrogen being generated in such a system would be of sufficient magnitude to require very large scale storage, such as is possible in aquifers or underground caverns.

Hydrogen to be used in the transportation sectors or in locations remote from the gas transmission system would be used as a liquid. LH_2 would be produced and stored in very large quantities. Over long distances, shipping of the LH_2 would be by rail; over short distances -- by truck.

Clearly, such a system is far from being implemented and faces all of the barriers associated with the development of the individual components and others. However, it is a logical extension of the other systems, and is one which could well have significant environmental impacts and it is therefore included.

3.3 SUMMARY AND CONCLUSIONS

The forecast hydrogen demand from all applications for the year 2025 is presented in Table 3.5. The industrial use of hydrogen predominates through the study period, accounting for 98.4 percent of the estimated demand. Hydrogen penetration into fuel markets will account for the remaining 1.6 percent of demand.

As an industrial feedstock, hydrogen will play in increasingly important role. As the quality of crude oil feedstocks becomes heavier, hydrogen will be required in greater quantities than at present to compensate for the higher carbon to hydrogen ratios typical of such crude oil. Synfuels production, whether from coal or tar sands bitumen, have the same upgrading requirements. Increasing reliance on liquid fuels from these sources is

TABLE 3.5

FORECAST HYDROGEN DEMAND - 2025

Application	2025 Hydrogen Demand Gm^3
Industrial Feedstock	
Petroleum Refining	7.50
Synfuels Production	11.40
Ammonia Production	11.00
Methanol Production	2.70
Other	2.02
Direct Fuel	
Aircraft	0.25
Rail Transportation	0.12
Road Transportation	0.21
Supplement to Natural Gas	-
Replacement for Natural Gas	-
Electricity Storage	-
Total	35.20

expected to be based on technologies which rely heavily on hydrogen addition processes. Upgrading liquid fuels is an indirect means of introducing hydrogen into fuel markets. Methanol and ammonia production will continue to rely heavily on hydrogen as an important feedstock for the synthesis of these chemicals. Hydrogen demand in the ammonia industry will grow in proportion to the expected growth in ammonia product demand. Hydrogen requirements for the methanol industry could be substantially greater than those forecast in Table 3.5, should new markets, such as its utilization as a transportation fuel, develop.

The primary source of hydrogen for these applications is likely to continue to rely on hydrocarbon based technologies. Partial oxidation, steam reforming natural gas and possibly coal gasification will predominate. Assuming continued availability and favourable pricing policies for natural gas, steam reforming will be the primary method for hydrogen production for industrial feedstock markets, as it is today. Depending on future prices of natural gas and electricity and improvements in electrolysis technologies, electrolytic hydrogen may be a candidate for some part of this market demand. It is likely to be small, however. By 2025, roughly 2.7 Gm^3 has been forecast to be supplied by electrolytic hydrogen.[32] This represents eight percent of the total industrial demand.

The low level of demand forecast for the direct utilization of hydrogen as a fuel reflects an early stage of penetration, based on the study team's judgement. Even this low level of demand presumes the development and practical application of technology which is not fully available at this time. It is far too early to assess future hydrogen fuel market prospects with any reasonable level of confidence. The true potential for hydrogen may be many more decades in the future than the year 2025.

Water electrolysis is assumed to be the primary source of hydrogen fuel. In combination with the estimated electrolytic hydrogen demand for industrial purposes, roughly 3.28 Gm^3 of electrolytic hydrogen or nine percent of total hydrogen demand could be required in the year 2025. This represents approximately 1920 MWe of generating capacity.

4. ENVIRONMENTAL EFFECTS OF HYDROGEN SYSTEMS

4.1 A SYSTEM FOR ENVIRONMENTAL ANALYSIS

Energy systems are a major source of environmental impact. The interactions of the energy and environmental systems are complex, and, for the most part, incompletely understood. One analytical framework for understanding and communicating the complexity of the interactions is environmental pathway analysis. (33) This analytic tool seeks to identify and characterize environmental interactions among five major components: origins, insults, pathways, stresses and damages.

The identification of the origins of environmental effects involves an identification of each component in the energy system. This includes all aspects of the system life from research through construction and operation to decommissioning. Ideally, every component activity of the energy system is considered from exploration, mining or harvesting through to processing, transportation, storage, distribution and use. The total system must be examined to ensure that all potential environmental effects are identified and to allow comparisons among alternative ways of providing the same energy service. Since different technologies may produce their most significant environmental effects at different stages, an evaluation of the whole system is necessary following the evaluation of each of the system components.

Whereas "origins" identify the activity source where environmental effects may be initiated, "insults" identify the direct nature of these effects. Where possible, this stage of the environmental analysis quantifies all transfers across the boundary between the environment and the energy system. This involves identifying all the resources used as inputs (including materials, energy and land) and all residuals and products which result (including emissions, effluents, solid waste, thermal waste, noise, radiation and direct physical transformations).

An exchange of materials or energy between the environment and the energy system does not in all cases mean that there is damage done to the environment. The next three components of the analysis attempt to determine the damage associated with the insults, initially by identifying the "pathways" of the insults. Pathways are the physical or chemical transformations which are triggered by the insults.

The physical and chemical pathways for environmental insults may result in altered environmental conditions which contribute to environmental stress. The conditions that may be altered to yield a stress include changes in acidity, chemical concentration, temperature, humidity or geology.

Finally, when the stress occurs at a point of potential environmental vulnerability, damages may occur. These damages may take many forms, including illness or injury to humans or animals, loss of economic or environmental goods or services, or aesthetic losses. In all cases, the damages are associated with the tolerance of the affected system to withstand the stresses imposed on them.

Only rarely is it possible to completely characterize each of the environmental pathway analysis components described above. An incomplete data base within any component circumscribes the analysis at the next level. As a system which categorizes and evaluates environmental impacts, obvious deficiencies in the data base become apparent, however, and contribute to establishing the research requirements to progressively build a better understanding. Data base deficiencies are common, even for mature energy systems. The difficulties are compounded when assessing the environmental effects of a developing energy system, such as one based on hydrogen.

The analysis of environmental impacts of hydrogen systems discussed in this chapter is limited in a number of ways. As most hydrogen technologies are only in the early stages of development, even the definition of the origin of environmental effects is speculative. While the nature of the technology can be broadly described, good process data are often unavailable. In some cases, this is a result of the information being commercially proprietary, in other cases because numerous process options are still under investigation. As a result, many of the "insults" are difficult to identify and few can be quantified with confidence. The depth of the analysis is, therefore, confined to establishing process technologies and estimating material and energy flows. The evaluation of the hydrogen system starts with the production technologies. The environmental effects of securing primary energy sources or producing the energy required to manufacture the hydrogen is outside the scope of this study. In the case of electrolytic hydrogen, for example, a source of electricity is given, and any impacts associated with its generation, from whatever source, are not included in the systems evaluation. While outside the scope of this study, these impacts may be significant and require thorough assessment. This study, therefore, is one component of a systematic environmental analysis, which at some point may be integrated with the results of other energy systems (i.e., nuclear or hydraulic electricity generation).

The balance of this chapter will first review the expected environmental and safety effects of the various component technologies of hydrogen systems. Each of the system applications discussed in chapter 4.2 will be reviewed for their environmental effects and finally areas requiring further investigation will be outlined.

4.2 GENERIC ENVIRONMENTAL ASPECTS OF HYDROGEN

This section will review the various process technologies required to support hydrogen system applications. Materials and energy flows are documented to the extent that information is available. The technologies reviewed are:

- production: steam reforming natural gas and solid polymer electrolysis
- liquefaction
- bulk storage: as a compressed gas, a cryogenic liquid or a metal hydride

- transmission and transport: LH_2 by pipe, truck or rail, and GH_2 by pipe
- small scale storage: as a gas or as a liquid
- use as a fuel: in fuel cells, internal combustion engines, or catalytic combustors

4.2.1 Production of Hydrogen

As discussed in chapter 3, steam reforming natural gas is the predominant hydrogen production technology and will likely remain so for the foreseeable future. The utilization of electrolytic hydrogen for fuel purposes shows potential at a low level over the next 40 years. Electrolytic hydrogen may also capture a share of the conventional steam reformed natural gas hydrogen markets in captive industrial applications. These two technologies are discussed below.

Electrolysis

There are several electrolysis technologies, including asbestos diaphragm cells and solid polymer electrolysis. Solid polymer electrolysis (SPE) has been chosen for analysis on the expectation that it will be the preferred technology by the turn of the century. Among the advantages of SPE are:

- high apparent conversion efficiency
- high current densities
- stability of electrolyte
- no electrolyte carry-over in generated gases
- absence of corrosive liquid electrolytes
- long life
- the ability to operate at high differential pressures and absolute pressures

The construction of a SPE facility is not expected to result in significant environmental impacts. The two main siting requirements are the availability of water and electricity, and thus for most Canadian situations, the SPE plant is likely to be constructed in fairly built-up areas near demand centres. If the source of electricity is hydraulic, there may be advantages associated with locating the SPE plant near the generating site, since the transportation of hydrogen over long distances (greater than 300 km) is expected to be less costly than electricity. Although there will be ground disturbance during construction, the land requirements of the plant are modest, and its construction is unlikely to create impacts any different from other types of plants of comparable scale. Land requirements for a plant producing one Gm^3 per year of hydrogen are estimated to be about one ha (based on utilization of 90 percent, one third land coverage, and operating at 82 percent efficiency. (34)

The major gaseous by-product of SPE is oxygen, which is produced at 0.5 the volume rate but eight times the mass rate of hydrogen. The co-production of large quantities of oxygen is a potential concern that has not been adequately addressed in the hydrogen research undertaken to date.

In theory, the oxygen released to the atmosphere is extracted when the hydrogen is combusted, and there is thus no net change in atmospheric oxygen. The cycle time from oxygen release to the oxidation of hydrogen is relatively short, particularly when viewed in a geological time frame: a time frame that is appropriate if comparisons are being made to fossil fuel use. A major concern about conventional energy use and the environment is the build-up of CO_2 in the atmosphere, a consequence of the extraction of oxygen from the atmosphere for the combustion of fossil fuels. This problem is not aggravated by the production of hydrogen from water using electrolysis. It is alleviated only to the extent that electrolytic hydrogen replaces fossil fuels as a source of energy.

Oxygen can be collected for sale for such uses as sewage treatment and medical use, and to improve the efficiency of wood, solid waste or fossil fuel combustion. Using oxygen for combustion rather than air will decrease some types of air pollution, especially nitrogen oxides.

In practice, "by-product" oxygen is likely to cause problems. The present market for oxygen is small. In 1978, 155 016 ML of oxygen were sold in Canada. (35) This amount of oxygen would be produced from only 0.3 Gm^3 of electrolytic hydrogen production. Oxygen production surplus to demand is of concern because oxygen is highly oxidizing, creating a potentially serious fire hazard if it comes into contact with oil, grease or other combustibles. While global net atmospheric oxygen concentration may not be affected by the use of electrolysis to produce hydrogen fuel, local variations at both the SPE plant and the location of combustion may be significant. A review of the literature uncovered almost no attention to this potential problem.

Inputs to the electrolysis unit are primarily electricity, water as a feedstock and for cooling purposes, and chemicals for water treatment. Water demand as a feedstock is about 900 million litres per Gm^3 of hydrogen produced. The demand for cooling water is about 100 times as large, or 90 billion litres (90 GL) per Gm^3 H_2. (34) Cooling water is not consumed in the process (as is the feedstock water) but is returned to the source, at a higher temperature. To put this demand into perspective, 90GL is equivalent to the current yearly water demand of a residential community of 50 000 people. (36)

Process water would be drawn directly from a waterbody; using city water would probably be prohibitively expensive. In either case, the water requires treatment to prevent the deposition of sludge and scale on the catalytic surfaces.

Process water flows through a sand filter bed to remove any suspended solids. Flow through the carbon filter removes any organic constituents (activated charcoal filter). Demineralizers contain a 'mixed-fixed' bed of pelletized synthetic organic resins, capable of selectively removing undesirable cations (calcium and sodium) and anions (chlorides and sulphates) by exchanging radicals with hydrogen (H^+) and hydroxyl (OH^-) ions respectively. Regeneration of resins is accomplished by bathing mixed beds in concentrated acid and caustic solutions, which displace the previously absorbed impurities. Effluent is directed to sewage treatment for neutralization of acids and bases. Some of the impurities removed by the demineralizers are insoluble in water and settle out as a sludge. Others are more or less soluble. The amount of impurities removed varies with feed quality. Sand and carbon filters are cleaned by backwashing (reverse flow) to sewer treatment. Typically, these mineral impurities are no more harmful than scale found in electric water kettles. Table 4.1 presents an estimate of water purification effluents for three levels of dissolved solids in the feedwater. If the SPE plant is located in urban areas, the regeneration waste can usually be discharged into the municipal waste system. If settling ponds are used, care must be taken to ensure that chemically contaminated liquids do not leak into ground water supplies. Treatment will be required for rendering both the liquid and solid waste material inert, and a variety of suitable processes are commercially available.

Steam Methane Reforming

Steam methane reforming is the process that is currently used to produce most hydrogen. Methane (in natural gas) is reacted over a nickel catalyst with steam to produce hydrogen, carbon monoxide and carbon dioxide. The two major reactions are:

$$CH_4 + H_2O \rightarrow 3H_2 + CO$$

$$CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$$

TABLE 4.1

EFFLUENTS FROM WATER PURIFICATION FOR SOLID POLYMER ELECTROLYSIS

(per 10^9 m^3)

	$CaCO_3$ Equivalent of Dissolved Solids of Raw Water Supply		
	535 ppm	191 ppm	23 ppm
Regeneration water (L)	192,800	91,100	52,500
Water impurities (t)	270	108	34
Regenerant chemicals (t)			
H_2SO_4	341	266	103
NaOH	63	32	30
Total effluent impurities (ppm)	6,556	8,367	6,553
Total effluent pH	11.8	1.8	11.7

Source: Aerospace Corporation, 1979. Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems, prepared for U.S. Dept. of Energy, Aerospace Corporation Report No. ATR-80 (7788-02) -1.

Before reforming occurs, sulphur is removed from the natural gas feed. This usually is accomplished by reacting hydrogen with the sulphur to produce hydrogen sulphide (H_2S) and then absorbing the converted H_2S with zinc oxide, yielding zinc sulphite (ZnS) and water. The ZnS must be disposed of.

After the sulphur stripped natural gas passes through the reformer, the product gas contains 42 percent hydrogen, 6 percent carbon monoxide, 50 percent water and trace amounts of carbon dioxide and methane. The hydrogen yield is increased by reacting the carbon monoxide with steam in a water gas shift converter to yield hydrogen and carbon dioxide.

Most carbon dioxide is removed using hot potassium carbonate which reacts with carbon dioxide and water to produce $KHCO_3$. This wash solution is regenerated in a steam stripping column where CO_2 gas is liberated and vented. The wash solution is recirculated to the absorber. Residual CO and CO_2 are removed by exothermic methanation reactions, producing very high purity hydrogen (less than 5 ppm carbon oxides). If necessary, residual methane can be removed by passing gases through molecular sieves.

Most of the reactions occur with the assistance of catalysts. The reformer uses a nickel catalyst, the water gas shift converters use Fe_2O_3 and Cr_2O_3 in the first (high temperature) stage, and CuO, ZnO and Al_2O_3 in the second (low temperature) stage, and methanation uses a nickel based catalyst. The life of these catalysts is limited; for example, the ZnO used for desulphurization lasts about five years and the reformer catalysts have a life of less than three years. Although catalyst disposal is not usually considered a problem, careful monitoring is advised if the scale at which steam methane reforming is used increases significantly. Catalysts are quite stable at ambient temperatures and provincial governments allow disposal at designated sites. Nickel bearing catalysts can be resold.

Significant quantities of carbon dioxide are vented to the atmosphere; in excess of six times more carbon dioxide than hydrogen (by mass) is produced. This is an inherent problem associated with using fossil fuels as a primary source of energy. It is feared that increases in the concentration of carbon dioxide in the atmosphere may lead to climate change. (37) This problem may be alleviated somewhat if the steam methane reforming plant can be situated near a urea plant, or near greenhouses as CO_2 supplements increase plant yields. (38)

Steam methane reforming requires significant quantities of water and energy. Water is used in boilers and for cooling, although most is returned to the source at a higher temperature. The fuel for the plant is usually natural gas. Emissions from steam reforming of natural gas are presented in Table 4.2. Modest quantities of electricity are also required.

It is difficult to compare emissions from steam reforming to those of electrolysis. Whereas electrolysis uses a secondary energy source (electricity), steam methane reforming uses a primary energy source (natural gas). If this distinction is ignored, SPE appears to be a much cleaner process. If the emissions associated with the conversion from primary fuels to electricity are included, then the relative quantities of emissions from the two processes are sensitive to the electricity supply mix. When emissions were weighted according to the fraction of electrical power produced in the United States, for example, the "clean" SPE process was estimated to produce 35 percent more CO, 3.43 times more NO_x, 281.8 times more SO_2 and nine times more particulates per unit product. (34) While electricity supply mix in Canada is different from that found in the United States, the conclusion emphasizes the importance of considering the source of electricity to the SPE technology.

The key components and the operation inputs and outputs are presented

TABLE 4.2

EMISSIONS FROM STEAM REFORMING OF NATURAL GAS

$(t/10^9\ m^3\ H_2)$

	HC	CO	NO_x	SO_2	Particulates
Reformer exhaust	9	52	2050	1.5	55
CO_2 scrubber regeneration	180	382	-	-	-
Total	189	434	2050	1.5	55

Source: The Aerospace Corporation, 1979. Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems. Aerospace Report No. ATR-80 (7788-02) -1, prepared for U.S. Dept. of Energy.

in Figures 4.1 and 4.2 for solid polymer electrolysis and steam methane reforming respectively.

4.2.2 Liquefaction

Most of the demand for hydrogen over the next 40 years will be as a feedstock to industry. For these applications, hydrogen will predominantly be used as a gas and as generated. Hydrogen fuel applications, however, although small (but growing rapidly) over this period, will require some form of storage. In many of these applications, liquid hydrogen (LH_2) will be the most convenient form for storage.

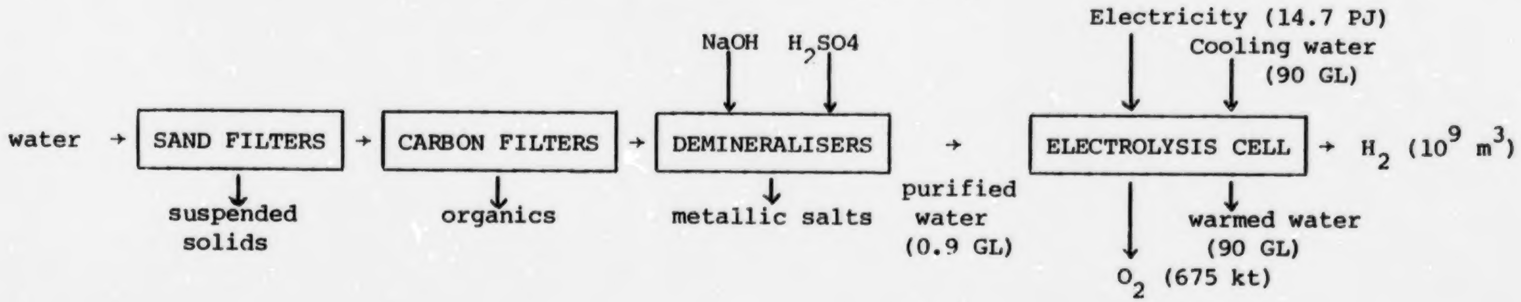
Using hydrogen as a liquid has two significant advantages over gaseous hydrogen: it increases the volume energy density of the fuel; and allows lower pressure storage vessels to be used. There are problems associated with the use of LH_2 including: theoretical and practical thermodynamic inefficiencies ; significant transfer and handling losses; chilldown losses; steady state boil-off losses; and the potential for fire. Another problem results from the two types of hydrogen involved, para-hydrogen and ortho-hydrogen. The difference is the direction of the electron spin. Gaseous hydrogen is 75 percent ortho-hydrogen, while the equilibrium liquid is nearly all para-hydrogen. The latent heat of conversion from ortho to para is greater than the latent heat of vapourization and only about 12 percent is recoverable. (39)

Cooling of the hydrogen occurs in stages using liquid nitrogen, hydrogen turbines and a Joule-Thompson expansion valve.

The liquefaction process is a relatively clean process. The major inputs are gaseous hydrogen, nitrogen, electricity, cooling water, and sulphuric acid for water treatment and dessicants and adsorpents. The

FIGURE 4.1

SOLID POLYMER ELECTROLYSIS



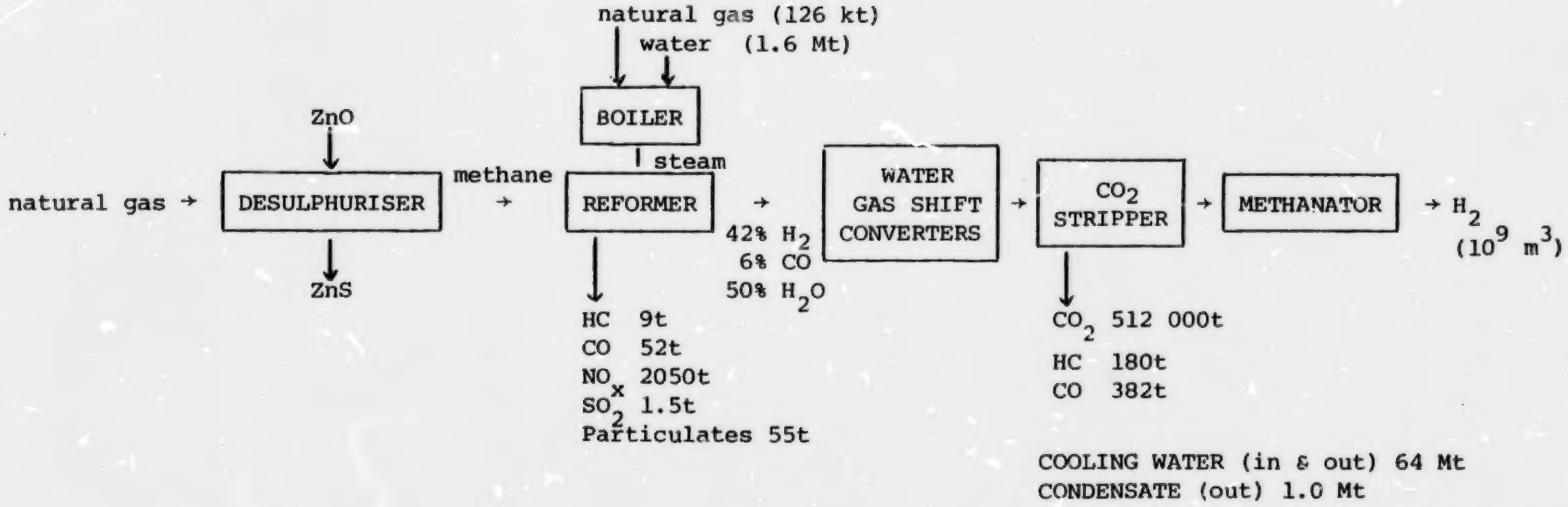
Sources: 1. Aerospace Corporation, 1979. *Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems*. Report No. ATR-80 (7788-02) -1. Prepared for the U.S. Department of Energy, Aerospace Eastern Technical Division, El Segurda, California.

2. L.J. Nutall, 1978. Water Electrolysis Using Solid Polymer Electrolysis. *Symposium for Hydrogen Energy Distribution*. Institute of Gas Technology (July).

3. M.S. Casper, 1978. *Hydrogen Manufacture by Electrolysis, Thermal Decomposition, and Unusual Techniques*. Noyes Data Corporation.

FIGURE 4.2

STEAM METHANE REFORMING



Sources: 1. Aerospace Corporation, 1979. Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems. Report No. ATR-80 (7788-02) -1. Prepared for the U.S. Dept. of Energy. Aerospace Eastern Technical Division, El Segunda, California.

2. M.S. Casper, 1978. Hydrogen Manufacture by Electrolysis, Thermal Decomposition and Unusual Techniques. Noyes Data Corporation.

3. K.E. Cox, K.D. Williamson Jr., 1977. Hydrogen: Its Technology and Implications, Vol. I: Production Technology. CRC Press.

major outputs are liquid hydrogen, impurities from the hydrogen feed (where hydrogen is produced from steam reformed natural gas), hydrogen leaks, and waste heat.

Energy use for the liquefaction plant is large. A typical 250 tonne per day plant would require on the order of 130 MW of electrical capacity. (40) The unit electrical requirements are thus on the order of 12.5 kWh per kg LH_2 (45 GJ per tonne LH_2). A tonne of LH_2 has an energy content of about 145 GJ, and 12.3 percent of the mass input hydrogen is lost. (40) The overall energy efficiency is thus about 68.9 percent.

These efficiency losses suggest a large demand for water for cooling. For each tonne of LH_2 produced, about 45 GJ of waste heat must be removed. Assuming the temperature increase of the cooling water will be about 6°C, in the order of 1.8 ML of water per tonne is required, or about 450 ML per day for a 250 tonne per day plant. This level of water use is equivalent to the requirements of a city of 100,000 persons. (36)

To date, most experience is with liquefaction of hydrogen produced by steam methane reforming. SMR hydrogen contains a small quantity of impurities and these are removed during liquefaction. About 8 100 m^3 of tail gas is produced per tonne of LH_2, and this gas consists of about 45 percent H_2, 21 percent N_2, 21 percent CO and 13 percent CH_4. The gas can be used as a fuel and has an energy content of about 7.8 MJ per m^3.

As mentioned earlier, about 12.3 percent of the gaseous hydrogen feed mass is lost during liquefaction. At least 65 percent of this loss occurs due to leakage, the remainder from product flash to storage, during purging or when the gas is stripped of impurities. (40) Although these losses naturally have some risk of accident associated with them, they are unlikely to be a serious environmental hazard.

Chemicals in the process include sulphuric acid for water treatment, and dessicants and adsorpents which are used at the rate of about 192 kg per tonne and 3 kg per tonne respectively. (40). These are used in the feed purifiers and thus probably will not be required for electrolytic hydrogen.

4.2.3 Bulk Storage

Hydrogen can be stored as a compressed gas, as a cryogenic liquid or as a solid in hydrides. The most suitable storage option varies with the various hydrogen applications as discussed in chapter 3. The environmental issues and safety requirements of the bulk storage options are discussed below.

Compressed Gas Storage

Underground storage of compressed gaseous hydrogen is the most suitable mechanism for storing very large quantities of hydrogen. Underground storage is a well developed technology which has been used extensively for natural gas. An underground hydrogen storage facility of the same size as an average underground natural gas storage facility would have an energy capacity of about 6.5 PJ. By comparison, the largest existing LH_2 facility has an energy capacity of only 0.04 PJ.

Underground storage systems have straightforward requirements: gaseous hydrogen is compressed and injected into an underground container. There are four types of underground storage used for natural gas and all are expected to be suitable for hydrogen storage. Storage may occur in depleted oil or gas fields, aquifers, salt domes and mined caverns. Characteristics of representative aquifer and salt cavern storage facilities are shown in Table 4.3. As required, the stored hydrogen is extracted, cleaned to remove any contamination caused by

TABLE 4.3

REPRESENTATIVE STORAGE FACILITY DATA

(Typical Natural Gas Facilities)

	Aquifer Storage	Salt Cavern
Location	Galesville - Northern Illinois Gas Media Field	Transco Energy Co. Eminence Dome
Average depth (m)	610	1 890
Volume capacity (m^3)	5.83×10^8	8.27×10^7
Maximum operating pressure (MPa)	6.37	27.2
Cushion volume (m^3)	4.53×10^8	2.61×10^7
Cushion pressure (MPa)	6.37	8.79
Deliverability (m^3 per day)	2.83×10^6	1.06×10^7
Injection/Withdrawal wells	5	2
Observation wells	8	-
Installed compressor power (kW)	1 866	1 492
Storage area (m^2)	230	-

Source: Foh, S., Novil, M., Rockar, E., Randolph, P., 1979. Underground Hydrogen Storage, Report No. UC94D. Institute for Gas Technology.

storage, and, if necessary, compressed for injection into a pipeline distribution system.

Underground storage leads to three major concerns: safety issues, air pollution and water pollution. Other minor concerns include noise and land use.

Transferring the natural gas based technology to hydrogen must recognize the different characteristics of these two fuels. Several safety related aspects must be considered. For example, at pressures above 13.8 MPa, hydrogen embrittlement becomes a problem. With gaseous systems, internal embrittlement, environmental hydrogen embrittlement and hydrogen attack have to be taken into consideration when choosing construction materials, to avoid the possibility of materials degradation and ultimately the loss of hydrogen containment.

Hydrogen leakage rates by volume are expected to be three times those of natural gas. Since the energy density of natural gas is approximately three times greater than hydrogen, leakage rates are essentially equal on an energy basis. Because of hydrogen's wider flammability range in air, however, above ground leakage is a particular safety concern. More stringent design and equipment specifications are required for a hydrogen facility relative to natural gas storage systems.

In an underground storage system, contamination of the withdrawn gas can result from: partial saturation with water vapour, subterranean gases coming out of an acqueous solution (e.g., nitrogen(and underground chemical reactions (e.g., $H_2 + S \rightarrow H_2S$). Contamination with water vapour is particularly dangerous if the gas is either transported or stored as cryogenic liquid. Water vapour will solidify at cryogenic temperatures.

Provisions must be made for emergency venting of the underground storage facility. Blowdown stacks are currently used in natural gas storage. The stack is of sufficient height to assure dispersal and to minimize the possibility of producing an explosive mixture at ground level. Ground level concentrations depend on atmospheric conditions, however, and maximum concentrations may occur under unstable atmospheric conditions. In comparing the discharge of hydrogen with natural gas in an emergency blowdown situation (34), short-term ground level concentrations exceeding the lower flammability limits were experienced for both. Though the minimum ignition energy for hydrogen in air (0.02 mJ) is a factor of ten lower than that for methane (0.29 mJ), both can be ignited by a weak ignition source.

Sources of air pollution include compressors, on-site electricity generating equipment and the boiler used to strip hydrocarbons and dehydrate the hydrogen gas before it is injected into the pipeline. Emissions from compressors are a function of a number of factors including the storage pressure, the compressor power required, and the fuel used. As indicated in Table 4.4, the power requirements for hydrogen are considerably greater due to hydrogen's lower volume energy density. For the same level of energy storage, hydrogen storage eliminates hydrocarbon and carbon monoxide emissions. Sulphur dioxide emissions may be increased by a factor of four to eight, however, if the hydrogen feed is pure (e.g., electrolytic hydrogen), there would be no SO_2 emissions. Nitrogen oxide emissions are significantly larger if centrifugal compressors are used, but may be lower if reciprocating compressors are used and an air/fuel mixture of 0.5 is maintained. In practice, the upper end of the range shown in the Table is more probable as the lean operation characteristic of the lower end would result in a power loss.

Fuel combustion for the boiler used for dehydration or liquid hydrocarbon stripping of the gas taken out of storage also produces emissions. As for compressor emissions, NO_x emissions are greater and HC and CO

TABLE 4.4

EMISSIONS FROM COMPRESSORS

(kg/(TJ/L))

Hydrogen

		Compressor size (MW)	Emission Factor			
			HC	CO	NO_x	SO_2
Case 1:	reciprocation	5.9	-	-	7.1-142.	0.023
	centrifugal	8.4	-	-	34.1	0.041
Case 2:	reciprocation	3.6	-	-	4.3-85.9	0.014
	centrifugal	3.8	-	-	15.3	0.019
Case 3:	reciprocation	2.5	-	-	3.0-59.8	0.009
	centrifugal	3.0	-	-	12.1	0.015

Natural Gas

		Compressor size (MW)	Emission Factor			
			HC	CO	NO_x	SO_2
Case 1:	reciprocation	1.5	8.2	2.6	20.3	0.003
	centrifugal	2.3	0.25	1.4	3.6	0.005
Case 2:	reciprocation	1.1	5.7	1.8	14.0	0.002
	centrifugal	1.3	0.14	0.8	2.1	0.003
Case 3:	reciprocation	0.8	4.3	1.4	10.7	0.002
	centrifugal	0.9	0.09	0.5	1.4	0.002

Notes:

1. The upper and lower end of the NO_x range for reciprocating hydrogen compressors correspond to fuel/air ratios of 1.0 and 0.5 respectively.
2. It is assumed that compressors are powered with the fuel being stored.
3. Cases correspond to suction/discharge pressures of 5.2/25.9 MPa, 4.8/13.8 MPa, and 3.4/6.9 MPa for cases 1, 2 and 3 respectively. Case 1 is typical of a depleted oil or gas field, Case 2 of an aquifer and Case 3 of the lower end of the storage pressure spectrum.

Source: Derived from Smalley, W.M. 1979. Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems. Aerospace Corporation Report No. ATR-80 (7788-02) -1, prepared for U.S. Dept. of Energy, Division of Energy Storage, Wash., D.C.

emissions are lower for hydrogen than natural gas. In fact, NO_x emissions would be about 3.3 times as great, because of the larger amount of hydrogen requiring treatment. Boiler emissions quantities are, however, relatively small compared to compressor emissions.

Where underground storage uses natural reservoirs, the walls of the "containers" will not be smooth and inert, and some interaction with the stored hydrogen may result. In the case of depleted oil or gas fields, residual hydrocarbons may be present and in salt caverns, salt may be present in the extracted hydrogen. These impurities may create a water pollution hazard when removed from the product gas. Table 4.5 is an example of the pollutant loadings for one underground natural gas storage facility using a depleted oil/gas field. Pollutant loadings will, of course, vary with the type of reservoir, its size and geology, and the gas withdrawal rate. In general, the pollution generated per unit energy stored can be expected to be four times higher for hydrogen than natural gas because of its lower volume energy density. As indicated in the Table, waste water from underground storage systems can be highly contaminated. At the particular site assessed, the waste water is trucked to a water treatment and disposal location where the solids are settled out in holding ponds. The remaining liquids are pumped to a sewage treatment plant.

Noise and land use are other potential areas of concern with underground storage. Sources of noise include the compressors, dehydration facilities, electrical generators (if installed), coolers, valves and fittings. Highest noise levels at natural gas facilities occur around the compressors where levels of 97 dB have been measured. (34) The higher compressor capacities needed for hydrogen storage could lead to levels of 103 dB. To achieve a background noise level of 45 to 60 dB, a 1.5 km buffer zone is necessary. (41)

Because of hydrogen's low volume energy density, land use is greater for hydrogen than for natural gas. Surface area requirements are

TABLE 4.5

WATER POLLUTION FROM WITHDRAWAL OF NATURAL GAS STORED IN A DEPLETED OIL/GAS FIELD

(kg/PJ)

Total dissolved solids	7 400 - 25 000
Suspended solids	10 - 60
Ferrous ion	1 - 11
Ferric ion	0.75 - 13
Phosphate	100 - 360
Ammonia	20 - 70
Copper	< 0.02 - 0.25
Zinc	0.05 - 0.20
Lead	0.13 - 0.60

Notes:

1. Units are kg/PJ of natural gas withdrawn from storage.
2. Both the type and quantity of pollutants produced will vary depending on site specifics such as type of reservoir, reservoir size and geology, and gas withdrawal rate.
3. Pollutants from hydrogen storage are likely to be much higher because hydrogen's volume energy density is only about 0.25 that of natural gas.

Source: Aerospace Corporation, 1979. Environmental Analysis and Assessment of Selected Hydrogen Production and Storage Systems. Report No. ATR-80 (7788-02) -1, prepared for the U.S. Department of Energy. Aerospace Eastern Technical Division, El Segunda, California.

estimated to increase by factors of 1.3 to 2.0 for storage in depleted oil/gas fields and aquifers, and by 1.0 to 4.0 for storage in salt domes and mined caverns. (34)

Bulk Liquid Hydrogen Storage

Bulk liquid hydrogen is stored in large, above ground storage tanks or dewars. The dewars are usually spherical (to minimize surface area) also double walled and highly insulated using vacuum perlite or vacuum multilayer insulation, which offer very high thermal resistance.

The major concerns with bulk LH_2 storage are safety and heat leakage.

Cryogenic storage temperatures may cause metal embrittlement; close attention to construction materials is required. The inner dewar wall is constructed of metals which retain their ductility and do not become brittle at liquid hydrogen temperatures. Face centered cubic metals and alloys such as aluminum, copper, nickel and austenitic stainless steels are recommended. Mild steels are adequate for outer wall construction as cryogenic temperatures are not experienced.

Thermal conductivity of the storage vessel must be kept to a minimum. The spacing between the walls is 1 to 50 microns and is maintained under a high vacuum. For added insulation, packing material such as perlite, silica aerogel, diatomaceous earth, fused alumina or phenalic spheres is added. Highly reflecting radiation shields separated by spacers along with a high vacuum may also be used. The evaporation of liquid hydrogen in a dewar is continuous and must be vented. The vent system is designed to carry vented hydrogen to a safe release location. For extensive gas venting, a venting stack or a burn pond are required. (51) Cold gas temperatures may cause ice accumulation, thereby blocking the vent. The resultant excess pressure may rupture the container, causing a detonation. (52)

Hydrogen dewars are frequently diked as an added safety precaution. The dike confines the liquid contents of the dewar in the event of a spillage. A water deluge system has been adopted by NASA (53) as a safety precaution for adjacent storage dewars in case of conflagration.

All cryogenic liquid piping is vacuum jacketed to reduce heat gain. A burst diaphragm or relief valve is installed in every section where liquid hydrogen can be trapped.

Hydrogen storage will preferably occur out-of-doors where any hydrogen leaks can be quickly diluted below the flammability limit. When storage is required in a permanent building, adequate ventilation and elimination of all ignition sources is essential. All electrical boxes, connections, components and equipment in the vicinity of hydrogen operations are either in explosion proof housing or are purged with an inert gas.

Because hydrogen is a colourless and odourless gas, small leaks cannot be detected by the naked eye. Sensors are required. Sensors are available which will detect the presence of hydrogen gas in concentrations well below the lower flammability level. Types of sensors available include: optical sensors which detect ultraviolet or infrared radiation; thermal wire fire detectors which consist of lengths of special coaxial cable connected to a bridge circuit to detect any temperature increase above a set value.

Instumescent paints have also been used to detect hydrogen fires. These paints char and swell at low temperatures (200°C) and emit pungent gases. In any storage area, both a gas sensor and fire detector sensor system is required. For indoor storage areas, gas sensors should be located in any area where an accumulation of hydrogen gas is possible.

Hydrogen is highly flammable and an explosive hazard exists. Even weak ignition sources such as matches, sparks, and hot surfaces will cause deflagration in open and closed systems. In a closed system, a deflagration may quickly develop into a detonation. Strong ignition sources such as shock waves tend to initiate detonations in open or closed fuel-air systems. Any tank rupture may quickly develop into a deflagration. Liquid hydrogen may become contaminated with air condensed and solidified from the atmosphere or by accumulation of trace levels of contaminants introduced in manufacturing. Contamination creates highly unstable conditions potentially leading to detonation.

Heat leakage is a concern because leakage tends to decrease the overall system efficiency, thus requiring a larger infrastructure and increasing environmental impacts upstream of the storage facility. To reduce heat losses, high insulation levels are used. Two types of insulation are in common use: vacuum perlite (with an annulus pressure of less than 15 Pa and an effective thermal conductivity of 0.9 mW per m/K) and vacuum multilayer (with an annulus pressure of less than 0.15 Pa and an effective thermal conductivity of 0.02 mW per m/K. (42) Table 4.6 presents typical boil-off rates for containers of various sizes. It is apparent from the table that boil-off is much higher in smaller containers.

Metal Hydrides

Hydrogen can also be stored in metal hydrides. Certain metal alloys absorb hydrogen into their molecular structures. The hydrogen is released by heating the alloys. Among the advantages of storing hydrogen in hydrides are their relative safety from the risks associated with explosions and their high volume energy density.

Storing hydrogen in hydrides requires neither high compression vessels nor cryogenic technology. Hydrides are relatively stable and inert. In one demonstration, a shotgun was fired at a hydride tank, which resulted in a small flare which quickly self-extinguished. (32) Hydrides

TABLE 4.6

TYPICAL LARGE SCALE DEWAR SIZE AND PERFORMANCE

Insulation	Container Volume (kL)	Boil-off per day
vacuum multilayer	50	0.22
vacuum perlite	110	0.80
vacuum perlite	380	0.18
vacuum multilayer	760	0.07
vacuum perlite	1 900	0.08
vacuum perlite	3 400	0.03

Notes: 1. Vacuum perlite numbers are for densities of 130 to 150 kg/m^3.

2. Large-scale boil-off is reused or recirculated.

Source: Cox, K.E., Williamson, K.D., 1979. Hydrogen: Its Technology and Implications, Vol. II. CRC Press.

are probably the safest medium for storing hydrogen, particularly for stationary application, and therefore best suited for storage at or near built-up areas.

Metal hydrides have volume energy densities greater than liquid hydrogen. (43) This suggests that they are a preferred option where space is at a premium.

There are, however, a number of concerns about hydrides. When hydrides are charged, heat is produced; to discharge the hydrides, heat is applied. Since the timing of the two is mismatched (otherwise storage would not be required), there will be waste heat to be carried away when charging and there will need to be a source of heat for discharging. Both of these activities will have some environmental impact, although neither is expected to be serious.

The second potential concern is the hydride itself. In some prototype installations, special care had to be taken to ensure that small quantities of hydride particles did not leave the storage reservoir with the discharging gas. (43) As this problem will need to be solved for hydrides to work effectively, it is unlikely to remain an environmental concern. The hydrides are expected to have a limited life. No documentation of either the life expectation of hydrides or of appropriate disposal methods for spent hydrides is available.

4.2.4 Transportation and Transmission

At present, hydrogen is shipped primarily by rail or truck, either in compressed gas cylinders, or as a liquid. These modes of transport are likely to persist over the near to medium term. Over the longer term, or in special circumstances, liquid or gaseous hydrogen may be shipped by pipeline. Each of these modes will be discussed.

Compressed Gas Transport

Compressed gas cylinders are used for the merchant markets where the individual purchaser's demand for hydrogen is small. Hydrogen gas cylinders have also been proposed for onboard storage in automobiles, using essentially the same storage vessels as currently employed for compressed natural gas. Tube tanks on truck trailers are also common, with capacities between 1 100 and 3 700 m^3 at 17 MPa. (44) The transport of large quantities of compressed hydrogen gas by either method is unlikely as only relatively small quantities of hydrogen (and therefore energy) can be transported at a time.

Tube trailers are delivered to the customer location, connected to a hydrogen bulk storage system, and emptied. The full carrying capacity of the tube trailer cannot be completely utilized as hydrogen can be discharged into the customer's bulk storage system only to the point where the pressure inside the tank reaches the receiving pressure of the storage system.

The vehicles used to transport compressed hydrogen are a source of air pollution. Again, hydrogen's low volume energy density results in a greater level of emissions than is associated with other fuels. The delivery of the same quantity of energy requires more trips. Table 4.7 presents typical emissions from diesel fuelled trucks. Also presented are estimates of emissions per unit of energy delivered.

Liquid Hydrogen Transport

Transporting hydrogen as a liquid permits larger volumes of hydrogen to be shipped at any one time compared to gaseous transport. Over short distances (less than 200 km), road transport is commonly used. Over longer distances, transport by rail or marine modes can be utilized. Typical container sizes for road, rail and barge transport are 50 ML, 100 ML and 1 000 ML respectively.

TABLE 4.7

EMISSIONS FROM TRUCKS DELIVERING COMPRESSED HYDROGEN[1]

Emission Type	Vehicle Emission (g/km)	Emission per Product Delivered ($g/m^3/100km$)
Particulates	0.82	0.068
SO_2	1.74	0.146
NO_x	13.02	1.086
HC	2.88	0.240
CO	17.82	1.486

Notes: 1. It is assumed that the truck is diesel fuelled, has a fuel economy of 45.2 L/100 km and a capacity of 2 400 m^3. It is assumed that emissions per kilometer are the same whether the truck is going to or from the destination of the GH_2.

Sources: The Mitre Corporation, 1978. Environmental Data for Energy Technology Policy Analysis. Report M78-74. Prepared for the Division of Environmental Impacts, Office of Technology Impacts, Office of the Assistant Secretary for the Environment, U.S. Department of Energy.

Barnstaple, A.G., Petrellis, A.J., 1981. Hydrogen: A Challenging Opportunity, Vol. 3: Hydrogen Supply. A Report prepared for the Ontario Hydrogen Energy Task Force, Toronto.

Liquid hydrogen tanker trucks are double-walled with the annular space under a high vacuum condition. Additional insulation, similar to that used for cryogenic storage, discussed earlier, is incorporated into the tank design. The inner wall is constructed of materials which will remain ductile at cryogenic temperatures. Suitable materials include austenitic chromium-nickel alloys, certain copper alloys and aluminum. All vessels and piping are designed to at least meet ASME codes and piping standards for the pressure and temperatures involved. Should a rupture occur, a fire followed by a detonation is highly likely.

Overfilling the trailers can pose a safety hazard. Sufficient vapour space must be provided to allow for liquid expansion and proper hold time. To prevent overfilling, trailers are equipped with accurate liquid level gauges and a sensitive fuel trycock system.

Vehicles are designed such that no venting en route is required. The "hold" time is adequate for a coast to coast delivery route. Should a pressure buildup occur, the trailer contents are allowed to vent, by one of several methods. The Air Products venting method is driver controlled. If the driver notices a rapid tank pressure rise, the trailer is driven to a location where manual venting may safely take place. The venting method used by Union Carbide is not driver dependent. The venting hydrogen is warmed through a heat exchanger. Its pressure is used to drive an air fan which dilutes the hydrogen below its lower flammable limit before discharging.

Hydrogen has a high diffusion rate and small leaks will quickly be diluted below flammable limits. In the case of a large spill, flammable hydrogen air mixtures are quickly formed but are rapidly dispersed due to hydrogen's buoyancy. Under normal conditions, a 2 000 litre liquid hydrogen spill will diffuse to a non-explosive mixture after about one minute. In the case of large cryogenic liquid spills, vapour rich clouds may be formed which extend to appreciable distances from the spill. This phenomenon has been experienced with natural gas (48) and similar characteristics are expected for hydrogen. The vapourization of the liquid can cool large masses of air. The temperature of hydrogen gas just after vapourization from the liquid is less than -418°F. At these low temperatures, the density of hydrogen vapour is greater than that of air at normal temperatures and pressure. The result of the large, cool air masses and low hydrogen density is the formation of a hydrogen rich cloud.

The most accident prone point in the transportation system is in loading and unloading. Static discharge grounding is one of the first steps required in this procedure. All trailer piping, transfer hoses and the receiving customer's station piping are purged with an inert gas such as helium or nitrogen to ensure that all air is removed prior to hydrogen introduction. The inert gas is then flushed with cold hydrogen gas from the vapour space. This procedure is well established and essential for accident prevention.

Liquid hydrogen may cause freeze burns to the eyes or skin, if contact is made with either the hydrogen or frosted pipes or valves. Protective apparel such as gloves, glasses, long-sleeved shirts and long pants must be worn by personnel.

Whenever hydrogen is transported by truck, there is some danger of a traffic accident. The average trailer carries approximately 2 000 kg of liquid hydrogen. Quantity-distance relationships for the protection of personnel near liquid hydrogen storage (48) indicate that for a fire involving 2 000 kg of hydrogen, anyone within a 50 metre radius is in danger of thermal radiation.

To date, the hydrogen industry has an enviable safety record. Air Products and Chemicals, Inc. report no serious accidents resulting in product loss and an average distance between accidents of 1.2 million km. (49)

Rail cars contain roughly three times the volume of liquid hydrogen contained in a tank truck. In the case of an accident involving content release, a greater area will be damaged in the case of rail transport. Since rail cars generally travel through less populated areas, the actual danger to the general public may be less pronounced.

Rail cars also have a double wall construction and are highly insulated. Safety concerns dealing with hydrogen embrittlement due to the cryogenic temperatures and hydrogen leakage are similar to those experienced with tank trucks and storage vesses.

A major concern of hydrogen tank cars is derailment. In a derailment, a tank car may be ruptured by the couplers of adjacent cars. Once ruptured, fire is instantaneous. In a closed system, there is also the possibility of a detonation. Venting of adjacent cars would add to the size of the fire. These cars must be cooled to prevent excessive venting.

Volume energy density (VED) differences suggest different impacts for LH_2 compared to other fuels such as propane and gasoline. The number of vehicle kilometres per unit energy delivered is almost directly proportional to VED. Vehicle kilometres per unit energy delivered gives an indication of the relative quantities of emissions and the relative incidence of accidents. VED's for gasoline, propane and LH_2 are presented in Table 4.8.

TABLE 4.8

RELATIVE IMPACTS OF TRANSPORTING VARIOUS
FUELS SUGGESTED BY VOLUME ENERGY DENSITIES

Fuel	Volume Energy Density (MJ/L)	LH_2 Index
Gasoline	34.66	3.37
Propane	25.53	2.48
Liquid Hydrogen	10.30	1.00

Indexed VED's are an indication of relative incidences of environmental impacts. For each unit of energy delivered, LH_2 would be expected to have over three times the quantity of emissions and accidents as gasoline. The environmental damages associated with an accident for each fuel will be different, of course, because of different handling or safety requirements and the specific physical or chemical characteristics of the fuels.

Gas Pipelines

Transmitting compressed hydrogen gas through pipelines appears to be a practical option, although there is limited experience, in Germany, for example. (45) In addition, there are long distances of pipe transporting hydrogen within refineries and other industrial plants. Most of the hydrogen pipeline experience, however, has occurred at low pressure with impure hydrogen. Higher pressures will be required for large scale distribution systems.

Hydrogen embrittlement is of major concern in a gaseous distribution system. Both internal embrittlement and environmental hydrogen embrittlement can be expected. Internal embrittlement occurs in nominally ductile steels while they are under a sustained load at tensile stresses below the yield strength. Cracks occur along either a concentration or a stress gradient. Depending on the hydrogen fugacity (free hydrogen under pressure) and the alloy used, there is an apparent threshhold ultimate tensile strength (34) below which hydrogen stress cracking does not occur. In hydrogen environmental embrittlement, the metal is plastically deformed. This phenomenon is more pronounced in high purity hydrogen, high pressures and low strain rates. At low pressures, it may be suppressed by the presence of hydrogen impurities.

Differences in hydrogen and natural gas VED, compressibility and other physical characteristics lead to different pipeline system design requirements. To have the same energy delivery rate, a hydrogen pipeline operated at about 5.0 MPa requires 3.8 times the compressor capacity and 5.5 times the compressor power of a natural gas pipeline. (45) Since air emissions are a function of compressor power, hydrogen pipelines will have significantly greater emission levels if the common fuels are used. Compressors are likely to utilize the fuel transported, however, and emissions from compressors using hydrogen will generally be lower for hydrocarbons, CO and SO_2, and higher for NO_x than those using natural gas.

Safety considerations for hydrogen pipelines do not appear to be significantly greater than for natural gas pipelines. While the volume of hydrogen leakage from the pipeline will be 2.4 to 6.5 times the natural gas rate, the overall energy leak ratio of hydrogen to natural gas may be as low as 1.04. (46) Hydrogen leakage is expected to diffuse rapidly and under normal conditions is unlikely to be a significant problem.

Liquid Hydrogen Pipelines

In theory, hydrogen can also be transmitted as a liquid in pipelines. Over the foreseeable future, LH_2 is likely to be transported over long distances only by truck, rail or barge. Liquid pipelines may be used for specific local distribution. NASA has a short, 500 metre vacuum jacketed, 25 cm diameter LH_2 pipeline for transfer from storage to launch sites, for example.

The practical problem with LH_2 pipelines is the need to maintain extreme low temperatures. The normal temperature for LH_2 is 20 kelvins. Even with the high insulation and the vacuum annulus around the transportation pipe, heat leak can remain a serious concern. It is estimated that heat leakage from supports, valves, joints and insulation would be about 50 watts per metre. At this conductivity rate, LH_2 boil-off may be pronounced leading to two phase flow (i.e., some proportion of LH_2 reverts back to its gaseous form). (47)

Air pollution will be generated in the production of the energy for operating the pipeline. In addition to the normal pipeline pumping requirements, LH_2 pipelines have special needs such as pumps for maintaining the vacuum jacket in the line. In general, pipelines are the most energy efficient mechanism for moving fluids, and pollution from operating can be expected to be low.

4.2.5 Small Scale Storage and Handling

Small scale storage will be required near the point of final use, for some hydrogen applications. Air, rail and over the road transportation applications in particular will require on-board storage, most probably as a liquid, but possibly as a compressed gas or in metal hydrides.

Liquid Storage

Liquid hydrogen storage appears to be the preferred form of storage for transportation vehicles, from rail and aircraft to trucks and automobiles. In all cases, vacuum insulated dewars are used, and the techniques for storage in high-energy use vehicles are much the same as for bulk storage, since relatively large volumes are required. Rail locomotives will pull an LH_2 carrying hopper and LH_2 aircraft will have large wing-tipped tanks.

In smaller vehicles, the relatively smaller volumes stored, and the greater number of vessels in use means that boil-off and safety become greater concerns. Boil-off rates for automobiles are likely to be about four percent per day, and pressure build-up rate is 4.3 to 4.6 kPa/L, depending on the liquid level in the tank. (59) Boil-off must be vented, which may create a significant problem in some locations, in parking garages, for example, if adequate ventilation is not available. Boil-off also has an energy cost associated with it, which translates directly into environmental and economic penalty.

Safety issues associated with small scale LH_2 storage have not been fully resolved, largely due to a lack of experience. The two major issues appear to be refuelling and collisions. Special precautions will be required for refuelling; automated equipment will have to be developed. Refuelling must not only be safe but perceived as safe by the general public, which will have no or low levels of training in handling hydrogen. The question of public safety in handling liquid hydrogen is still unresolved. (43)

Crash safety of on-board LH_2 storage tanks is still uncertain. (43) Lab tests on prototype tanks have demonstrated a degree of tolerance to structural damage, but much more thorough testing is required to understand the consequences of accidents involving vehicles with LH_2 storage.

Compressed Gas Storage

Hydrogen stored as a compressed gas will be similar to compressed natural gas (CNG) storage which is now being commercially introduced. No environmental problems have been associated with the use of compressed storage, and safety levels appear to be acceptable provided the necessary precautions are followed. These precautions include careful design of refill stations, trained and aware operators, and periodic inspection.

The use of small scale compressed gas storage will likely be extremely limited because of the relatively small volume of gas that can be stored in tanks of appropriate size and mass.

Metal Hydrides

Hydrogen storage in metal hydrides has been proposed for small-scale, portable storage, but is unlikely to be used extensively. The technique may be attractive where extra mass is not a liability. Metal hydrides appear to be safe and environmentally benign under normal operating conditions. In the event of collision, hydrides are likely the safest hydrogen storage technology, although the environmental effects of spilling hydrides from a ruptured tank have not been documented.

Refuelling hydride tanks is similar to compressed gas refuelling, except that cooling water is required for the waste heat released as the hydrides absorb hydrogen.

4.2.6 End Use

There are a number of possible technologies for recovering the energy potential of stored hydrogen, including fuel cells, internal combustion engines, and catalytic combustion. Each of these is discussed below.

Fuel Cells

Fuel cells permit hydrogen to be converted into useful energy at relatively high efficiency. Conceptually, a fuel cell is the opposite of an electrolytic cell. The hydrogen fuel combines with oxygen to yield water and electricity. This reaction occurs without an intermediate heat stage; the stored chemical energy is converted directly into electrical energy. The theoretical or ideal efficiency is 83 percent at 300 K. (56) Actual efficiencies are likely to be about 50 to 60 percent.

There are a number of fuel cell technologies, but it appears that alkaline fuel cells utilizing high purity electrolytic hydrogen will be the preferred choice in Canada. Alkaline fuel cells offer high performance, are well developed and do not require precious metal catalysts. (56)

The alkaline fuel cell consists of two major components: an air/CO_2 scrubber and the fuel cell power plant. Carbon dioxide must be removed from air to be used to oxidize the hydrogen since alkaline electrolytes will react with CO_2 from the air to form carbonates. Sodium hydroxide reacts with the carbon dioxide to produce sodium carbonate (Na_2CO_3 or soda ash) and water. The CO_2 scrubbed air and the hydrogen fuel are piped to the fuel cell power plant where they react electrochemically to produce direct current electricity, water and low grade heat.

Fuel cells have minimal emissions of pollutants. Since reactions are electrochemical and not thermochemical, the normally high emissions of NO_x produced by hydrogen fuels are avoided. Fuel cells have no moving parts except for the few fans or pumps that may be associated with the system design.

Internal Combustion Engines

Stock Otto and diesel engines can be successfully operated using hydrogen as the fuel. Some external engine modifications are required because of the differences in the properties of hydrogen. Table 4.9 compares the properties of hydrogen and gasoline. These properties require a major change in the way the fuel is admitted to the engine. Four main types of systems are possible: continuous mixture formation, timed port injection systems, low pressure direct cylinder hydrogen injection and high pressure direct cylinder injection.

The continuous mixture formation system involves a different carburetor suited to a gaseous fuel engine. To avoid severe backfires and erratic performance at high throttle openings, exhaust gases (water vapour) are recirculated to the carburetor. Although this system results in better fuel economy than is attained with gasoline, and low emissions (0.12 g/km NO_x), there is also power loss due to fuel charge dilution. This power loss may be as much as 50 percent.

Timed port injection systems take advantage of the wider flammability limits of hydrogen. In this system, the amount of hydrogen supplied is varied, rather than throttling the air as in gasoline engines. Thus, the carburetor and inlet manifold can be removed completely. This system is well suited for use of LH_2 since the cooled hydrogen/air mixture cools any hot spots and reduces pre-ignition. In addition, the cooler charge reduces NO_x emission and flashbacks and increases power.

The last two systems involve injection into the fuel cylinder, somewhat like a fuel injection or diesel engine configuration. This technique is the safest because flashback is virtually impossible; no combustible mixture is present anywhere but in the combustion chamber. Although pre-ignition is reduced, and engine thermal efficiency is increased, the engine is susceptible to incomplete combustion due to poor mixing, particularly at low RPM's.

Expected emissions from the utilization of hydrogen as a fuel system has been an important selling point for using hydrogen as a fuel. Emissions of CO, SO_2 and hydrocarbons from hydrogen engines are virtually eliminated. In the engines that have been converted to hydrogen, there has been wide variation in the NO_x levels measured. In some instances, emissions of NO_x have been considerably higher from hydrogen engines than from gasoline engines. Peak NO_x emissions occur in the vicinity of 0.8 equivalence ratio. Although these can be reduced significantly to about 0.24 g/km by operating at an equivalence ratio of 0.4, this results in a significant and probably unacceptable loss of power. As discussed above, the continuous mixture formation systems with extensive exhaust gas recirculation can keep NO_x emissions down tc a reasonable level. Performance features for the various types of conversions are summarized in Table 4.10.

Water vapour is another emission from hydrogen engines. Water emission will be directly related to fuel use. At a fuel economy equivalent to 5.5 L per 100 km (≃ 1.9 MJ/km), about 150 g/km of water is emitted. Although harmless, such an emission will probably produce more of an aesthetic impact than gasoline engine emissions, especially in cold weather when the exhaust gases will condense rapidly.

Jet turbines can also operate on hydrogen. Operation on hydrogen reduces emission of all pollutants, but increases water vapour emissions, a particular concern when flying at high altitudes where vapour trails are persistent. Table 4.11 summarizes estimated emission from jet engines operating at super-sonic and sub-sonic speeds.

Catalytic Combustion

Hydrogen has a very low ignition energy (.02 mJ vs 0.3 mJ for natural gas) and hence is easily oxidized. When hydrogen comes in contact with a suitable catalytic surface, low temperature (20-400°C) combustion can be sustained. The temperature is controlled by adjusting the feed rate.

Catalytic combustion is likely to be a significant technology in the hydrogen economy since it is the preferred technology for generating low temperature heat from hydrogen. Low temperature heat accounts for about 30 percent of all Canadian energy use. (58) Among the potential applications of this technology are residential space heaters, cooking devices, and industrial dryers and heaters.

Although catalytic combustion has a number of potential advantages, it is still at an early stage of development. Among the advantages of catalytic combustion are:

- ability to control temperatures
- practically negligible NO_x production (because of low temperature)
- low possibility of back-flashing or explosions

TABLE 4.9

COMBUSTION PROPERTIES OF HYDROGEN AND GASOLINE

	Hydrogen	Gasoline
Auto ignition temperature (°C)	585	440
Minimum ignition energy (mJ)	0.02	0.29
Flammability limits (Vol. %)	4 - 75	1.3 - 7.1
Stoichiometric mixture (Vol. $)	29.6	1.7
Lamina flame speed (cm/s)	0.63	0.08
Lower heat of combustion (MJ/kg)	119.7	46.4
(kJ/L)	8.63	33.4

TABLE 4.10

PERFORMANCE FEATURE OF HYDROGEN AUTOMOBILE ENGINES

(relative to gasoline operation)

	Power	Fuel Use	NO_x Emissions* (g/km)
Exhaust gas recirculation	0.50	0.50	0.12
Timed port	0.63	0.50	2.7
Low pressure direct injection	1.27	0.75	N/A
High pressure direct injection	≈1.00	>1.00	68 - 70% of gasoline
High pressure diesel	≈1.00	<1.00	0.56 g/km

*Note: Current NO_x emission standards are 2.5 g/km

Source: Wallace, J.S., Keffer, J.F., 1981. Evaluation and Testing of Hydrogen Fuels/Engines Systems. Phase I feasibility study, Dept. of Mechanical Engineering, University of Toronto.

TABLE 4.11

EMISSIONS FROM JET ENGINES

	Liquid Hydrogen		Jet A Fuel	
	sub-sonic	super-sonic	sub-sonic	super-sonic
NOx (g/kg Jet A equivalent)	4	low	12	3.7
CO (g/kg Jet A equivalent)	-	-	30	90
unburned hydrocarbons (g/kg Jet A)	-	-	4	0.3
odours	NO	NO	YES	YES
water vapour (kg/km)	52.3	97.1	26.6	48.8

Source: Bon, E., Buzzi, P., Jones, L., Wochke, C., 1982. Liquid Hydrogen: An Alternative Aircraft Fuel. Systems Design Department, University of Waterloo.

- ability to provide radiant heat
- no need for flues or chimneys
- high efficiency

Research into catalytic combustion is attempting to find inexpensive catalysts, and to correlate catalyst differential surface temperatures with fuel feed rates and compositions.

The major by-product of catalytic combustion is water vapour. This could present problems in well insulated, air tight buildings where excess humidity is already a concern.

A typical 1.5 kW catalytic hydrogen space heater that could replace an electric baseboard heater would produce about 0.34 kg/L of water vapour. Oxides of nitrogen would be generated at the rate of 0.16 mg/L.

4.3 APPLICATION SYSTEM IMPACTS

In this section, the proposed hydrogen fuel system and markets, discussed in the previous chapter, are combined with the information on the "generic" environmental and safety impacts of their component technologies discussed in the previous section. This is an essential step in the pathways analysis approach outlined in section 4.1. There are six issues that must be addressed which result from the interactions of the generic impacts and the systems and markets.

The first issue is synergistic relationships. Each of the component processes or technologies may affect or be affected by other components in a way that increases or decreases the environmental impact. For example, the high mass energy density of hydrogen permits LH_2 aircraft to consume less energy due to weight reductions which result in energy savings which in turn are translated into reduced environmental impacts right back to primary energy extraction. The low mass energy of hydrides in automobiles has the opposite effect.

Second, an important part of any environmental analysis is distribution considerations. Not only does the distribution of environmental insults or stresses affect the damages, but there is also a socio-political dimension. Those who benefit from the product of the damaging system may not be the ones who suffer the damages.

Related to distribution is the effect of scale on environmental stress. Damages caused by stresses may not scale linearly. In many systems there may be a threshhold level below which pollutants produce no damaging effect. Scale of a technology or plant may affect emissions. Large plants may have lower pollutant dumps per unit product because control technologies are more easily implemented on large plants. However, large plants may fail less gracefully and may create distribution problems.

Two other related issues are ease of mitigating damages and the degree to which damages are reversible. Damages may be acceptable if they occur over a short time (such as during construction) and the ecosystem quickly returns to normal. Similarly, systems which cause damage will be more acceptable if measures are available to mitigate those damages.

Finally, an important consideration in any environmental analysis is the extent of uncertainty; how confident can one be of the analysis and what are the possible implications of its being incorrect?

4.3.1 Feedstock Applications

Feedstock applications include both existing hydrogen uses, and a number of new hydrogen uses. In general, these systems require hydrogen as an integral process input. The alternatives which can be contrasted are thus different hydrogen production technologies (e.g., steam methane reforming vs. electrolysis) and conservation technologies which reduce the need for the hydrogen using system. The latter alternative is outside the scope of this study. The nature of the impacts of the two production technologies is different and it is thus not possible to state that one is clearly superior. Electrolysis does not contribute to the CO_2 climate problem but it does produce oxygen, the effects of which on the local environment are not well documented. Electrolysis also requires larger volumes of water (primarily for cooling). Finally, the two are not directly comparable because steam methane reforming requires a primary energy form as an input (natural gas) but electrolysis requires a secondary energy form (electricity).

4.3.2 Aircraft Systems

Aircraft fuelled with liquid hydrogen appear to have a distinct environmental advantage over regularly fuelled aircraft. The higher mass energy density of hydrogen relative to conventional jet fuels leads to utilization energy efficiency improvements of at least one-third. From an overall systems perspective, energy use is probably increased because of the energy costs of electrolysis and hydrogen liquefaction. Take-off noise is reduced, end-use emissions are lower, and shorter runways are required. There are no major sources of pollution from electrolysis through to end-use, although safety issues will have to be adequately addressed to minimize the risk of fires and explosions. For the projected market, infrastructure requirements are small and the public need have little involvement with hydrogen fuel systems.

4.3.3 Rail Systems

The proposed rail system involved liquid hydrogen transport, bulk storage, refuelling facilities and on-board storage, and fuel cells. The near term market identified was commuter rail systems. Liquid hydrogen use creates some safety concerns for this system because significantly larger volumes of LH_2 than conventional diesel fuel will be required, and the rail systems involve large numbers of members of the general public and operate in densely populated areas. Fuel cells are less polluting and more energy efficient than conventional diesel generators used on locomotives, but this energy saving is more than lost in the electrolysis and liquefaction processes.

4.3.4 Road Transportation

In road transportation, the technology for using hydrogen is still under development. Using hydrogen is likely to result in significant increases in NOx emissions if used on a large scale. Safety concerns have also yet to be adequately resolved. Infrastructure requirements for hydrogen will be large and there are overall decreases in system energy efficiency. Use of metal hydrides or compressed hydrogen gas will lead to an even greater net decline in overall system efficiency (this may still be acceptable, given that the primary energy source is different from conventional fuels). Technical considerations alone limited the probable market for hydrogen through 2025. A large probable market would have large risks associated with it.

4.3.5 Gas Supplementing

Supplementing natural gas was projected to have a small probable market. Given that the generic impacts of each component of the system are not severe, the overall impact is also quite small. Hydrogen's lower VED than natural gas will result in increases in storage requirements and emissions for compression. Overall, NO_x emissions will be increased by supplementing natural gas with hydrogen, but other emissions will decrease somewhat.

4.3.6 Electricity Storage

As in other systems, using hydrogen for electricity storage will result in net increases in total energy use and emissions of oxides of nitrogen. Environmental benefits may accrue if hydrogen peaking replaces fossil peaking since emissions of CO, CO_2, HCs and SO_2 are virtually eliminated.

4.3.7 Residential, Commercial and Industrial Systems and the Universal System

These systems will require extensive infrastructures and will tend to be more centralized than the other systems discussed. They will, however, probably be less centralized than conventional energy systems. As with the other systems, energy use to provide the same service is likely to increase, as are emissions of NO_x. The need for safety equipment and procedures (if not safety risks themselves) will increase. On the positive side, some impacts associated with using fossil fuels will be reduced, for example CO, CO_2, SO_2 and unburned hydrocarbon emissions will be reduced.

4.3.8 Summary

Over the stages of the systems considered, hydrogen appears to be relatively benign from an environmental perspective. There are, however, two significant impacts: an overall reduction in energy efficiency and an overall increase in emissions of oxides of nitrogen.

Because the number of stages and energy conversions associated with hydrogen increases, and each stage is less than 100 percent efficient, overall system efficiency tends to decrease. This decrease may be acceptable since energy sources which are non-renewable and depleting (fossil fuels) can be replaced by energy sources for which the supply is more abundant (electricity).

Although most air pollutants are reduced or eliminated with hydrogen, nitrogen oxide emissions tend to increase with hydrogen use. NOx is a contributor to acid rain, urban air pollution and other environmental problems. Since this is the major pollutant associated with hydrogen use, technologies may be developed for dealing with it. Over the 40 year time frame considered, NOx from hydrogen energy is not likely to be a significant environmental problem because the hydrogen market will be so small. It may be a problem, however, if there is significant growth in the use of hydrogen as a fuel.

Safety issues will be a concern over the transitional period of hydrogen fuel utilization. This concern arises not so much out of an inherent lower safety level for hydrogen but out of the need for different and somewhat unfamiliar safety precautions.

Finally, there are a number of uncertainties associated with the environmental impacts of hydrogen. These uncertainties suggest research and development requirements as discussed in the next section.

4.4 RESEARCH AND DEVELOPMENT REQUIREMENTS

A substantial level of technical research and development remains to be performed before hydrogen can be viewed as having near-term commercial prospects for introduction into fuel markets. The requirements span the entire energy system, from production through transmission/distribution, storage and utilization. A significant amount of technical R&D is already underway by private industry, government, universities and other research bodies, both in Canada and abroad. Future Environment Canada initiatives in this area should recognize the potential market demands for hydrogen as discussed in Chapter 3 in combination with the prospects of technical readiness and the environmental implications reviewed in the previous section. Three broad areas will profit by the involvement of Environment Canada or serve to enhance department's appreciation of evolving hydrogen applications. These are:

- assess near-term electrolytic hydrogen markets
- investigate in more detail, several macro environmental issues which may emerge from hydrogen applications
- establish a technology monitoring study group.

These areas are discussed below.

4.4.1 Assess Near-Term Markets

Hydrogen markets will continue to be predominantly based on the use of hydrogen as a feedstock to industry. A small but growing fuels market can be expected by 2025. Two areas which require more detailed investigation are: the substitution potential of electrolytic hydrogen for industrial hydrogen produced by steam reforming natural gas; and the market potential for electrolytic hydrogen in specialized "niche" applications.

The exact timing and extent of the opportunity to use electrolytic hydrogen in industry will, of course, depend on the relative costs of producing hydrogen from electrolysis technologies over natural gas or other hydrocarbon (e.g., coal) technologies. These costs will primarily be a function of capital requirements, electricity prices (in the case of electrolysis), natural gas or other hydrocarbon prices and the process efficiencies of each technology. While forecasting each of these variables is speculative, at some point electrolytic hydrogen may be a less expensive option than hydrogen produced from conventional technologies. Market sectors of particular interest will include:

- synthetic fuels upgrading which are projected to increase hydrogen demand by almost 700 percent. Coal and bitumen upgrading consume large quantities of hydrogen. Electrolytic hydrogen may have a role in at least supplementing these requirements, thereby decreasing the use of hydrocarbons in processing.

- ammonia production in Canada has traditionally relied upon cheap sources of natural gas in Western Canada. Hydrogen could be supplied by electrolysis where inexpensive electricity can be provided (at or near to a hydroelectric facility, for example). Hydrogen demand is expected to double by 2025.

Other potential sectors of interest include oil refining, methanol production and the metallurgical industry.

As indicated in previous sections, the production of electrolytic hydrogen has some environmental benefits relative to steam reforming, including: the displacement of hydrocarbon fuels for other applications; and the elimination of CO_2, particulates, hydrocarbons, sulphur and CO emissions.

An advantage of electrolysis technologies is that their application is generally independent of scale. Hydrogen production can be matched to the demand, whether large or small. The source of electricity is similarly not technically constrained by size (although the economics may be). Electrolysis may occur from electricity supplied by large nuclear or hydroelectric facilities or alternatively by smaller systems such as low head hydro, wind power or conceivably photovoltaic facilities. Niche markets might usefully be served by such smaller systems coupled to an electrolyzer. Northern and coastal communities or remote construction sites, for example, are commonly served by isolated power sources, mainly diesel plants. Escalating fossil fuel prices and delivery costs produce high electricity and final costs to such areas. A possible approach would be to couple small alternative electricity generating facilities to the local energy grid and produce hydrogen by electrolysis. Although the addition of an electrolyzer represents higher capital outlays and energy conversion inefficiencies, the availability of energy as a chemical or stored electrical energy could offset the disadvantages for local, remote situations. Emissions from the system would be expected to be much less than from diesel generation. Such niche market applications could have potentially attractive environmental benefits, especially in environmentally sensitive areas.

4.4.2 Macro Environmental Issues

The hydrogen fuel systems discussed in the previous section generally have more environmentally benign implications than the systems they would replace. The analysis has not, however, included the source of electricity to the electrolysis plant. If one was to incorporate the tangible and intangible environmental implications of large scale production of electricity, the conclusion from a "total" system perspective may be different. The most commonly referred to sources of electricity for electrolysis are nuclear and hydroelectric. Each have proponents and opponents from an environmental perspective and it has been beyond the scope of this study to comment on their relative advantages and disadvantages. From a policy perspective, any significant movement to greater electrolytic hydrogen production must establish the environmental impacts from these generating sources from a full systems perspective. The downstream environmental impacts of hydrogen impacts may very well be far more contentious than its actual production and use. At the levels of electrolytic hydrogen demand forecast in this study, the issue is probably mute where existing facilities act as the source of electricity. Large scale introduction, requiring either new or dedicated facilities will require evaluation to support the conclusion that hydrogen systems are environmentally advantageous over conventional sources of energy products.

Other areas requiring more detailed evaluation include:

- the implications of large scale release of oxygen. Oxygen is produced in significant quantities as a co-product with hydrogen from electrolysis. The electrolytic hydrogen demand forecast for 2025 would also produce 1694 GL of oxygen or almost 11 times the total demand for oxygen in 1978. While new markets may be found, large amounts of hydrogen may be simply vented. Local safety hazards and environmental degradation may result depending on the extent of the release.
- electrolytic hydrogen production and fuel cells technologies utilize catalysts for which information on type, materials and disposal or regeneration characteristics are often held as commercially confidential. The processing technologies are also unknown. The same is generally true for the various hydride storage options.
- end use emissions, although generally favourable relative to other fuels will be substantially higher in NO_x, water vapour and in the case of LH_2, evaporative emissions.

The significance of these issues is generally unappreciated at the moment.

4.4.3 Technology Monitoring

As indicated earlier, a substantial level of additional research is required before the various components of hydrogen fuel systems will be readily available. Many of the technologies have not developed to the point where an emphasis on establishing their environmental implications are under serious consideration. To the extent that the emphasis is still on establishing and choosing the process conditions, improving efficiency and generally trying to get a technology "to work", their environmental implications are unlikely to draw early attention. Technology monitoring will be a useful strategy for Environment Canada at this time. Once the technical issues have been resolved, the department can then more accurately assess their environmental effects. Options to be considered include:

- assigning responsibility to one or a number of individuals to monitor the technical literature on a consistent basis

- establishing a department representative on review committees such as the Hydrogen Energy Safety Committee which is to be established shortly. Representatives of a broad cross-section of industry, government, universities and standards bodies having an interest in hydrogen are to be included on the committee

- securing the cooperation of government research agencies and departments (such as NRC) to include environmental aspects in their hydrogen research projects. Some leverage and state-of-the-art assessment on technology development may be provided for otherwise privately sponsored development activities.

The intent of the monitoring function is to ensure that Environment Canada is kept abreast of the latest developments in applied hydrogen research and is then in a position to evaluate their implications.

5. CODES AND REGULATIONS

The development of hydrogen codes of practice is specifically based on the physical, chemical and thermal properties of hydrogen. Hydrogen is a colourless, odourless and tasteless gas. It is highly flammable with wide flammability ranges, and therefore requires strict adherence to industrially accepted standards and guidelines and compliance with existing regulatory codes, whether mandatory or not.

Hydrogen has been safely handled by industry for several decades, both as a high temperature gas and as a cryogenic liquid. Numerous standards, codes and guidelines for the handling of hydrogen have been developed by trade and interest groups and professional bodies, both in Canada and abroad. Many of these codes have been adopted by regulatory organizations. Others are followed by industry as a matter of safety.

Many Canadian codes and regulations are an adoption or refinement of existing American codes. Because of U.S.-Canadian trade relations, Canadian regulations are generally not significantly different from U.S. regulations. Although the U.S. network of codes and regulations is somewhat diffused and unorganized, it has generally proven adequate for the present quantity of hydrogen distribution and use.

5.1 CODES AND REGULATIONS - CANADA

There are five official standard writing bodies in Canada. These are: Canadian Gas Association, the Canadian Government Standards Board, the Canadian Standards Association, the Canadian Underwriters Laboratory and le Bureau des Normes du Quebec. Any standards or guidelines developed by professional or interest groups are reviewed by these standard writing agencies before they are formally institutionalized as regulations by government bodies.

Few Canadian regulations deal specifically with the safe handling of hydrogen. In many instances, compliance with safe codes of practice are implied. Where there are no specific regulations, industry has taken responsibility in developing and following standards and guidelines to ensure safe production, transportation and usage.

5.1.1 Transportation

Regulations under the Transportation of Dangerous Goods Act (currently in the proposal stage) will provide a single set of safety standards, regulations and requirements for the country. These regulations would be applicable to all modes of transport, except pipeline and intra-provincial road, and would include storage at loading site, loading procedures, and transfer to specification storage vessels at a consumer location. This act will be divided into three parts:

- goods classification
- safety standards for the containment of dangerous goods, safety requirements respecting handling and transportation prohibitions and limitations, training and education of personnel, and notification and reporting of accidents
- designation of inspectors, applications for permits and ticketing offences

Under this Act, compressed hydrogen (UN1049) and refrigerated liquid hydrogen (UN1966) are classified as highly flammable.

The Transportation of Dangerous Goods Act will replace existing federal regulations for transportation of dangerous goods under the Aeronautics Act, the Canada Shipping Act, the Explosives Act and Railways Act. Depending on the physical and chemical properties of flammable liquids, present regulations indicate that they must be shipped in specification containers which are constructed of materials that will not react dangerously with or be decomposed by the chemical being transported.

At the request of Transport Canada, the Canadian Standards Association has developed standards for transportation containers. Standard B338, published June 1982, deals with standards in the design, construction and inspection of highway and portable tanks. Standards B339, scheduled for publication January 1983, deals with standards for cylinders, spheres and tubes. These standards have not yet been adopted by any regulatory bodies.

Pipeline transportation, both inter and intra-provincial, is regulated by the National Energy Board Act and administered by the National Energy Board. Standards have been developed for conventional petroleum fuels. No regulations exist for pipeline transportation of hydrogen either as a compressed gas or cryogenic liquid.

Intraprovincial road transportation is under provincial jurisdiction. This sector has not been heavily regulated with respect to transportation of hydrogen. Industry has taken responsibility in ensuring safety by following existing standards and guidelines.

Codes for storage and handling of propane, natural gas, butane and some other hydrocarbon fuels have been developed. Some of these have been adopted by provincial regulatory bodies. For example, the Gasoline Handling Act of Ontario specifies design and construction of tanker cars for the transportation of gasoline and diesel fuels.

The Energy Act includes transportation, storage and handling regulations for propane, natural gas and several other hydrocarbons.

5.1.2 Industrial Insurance Requirements

Industrial insurance agencies play an important role in ensuring compliance to safety codes and standards. Under current regulations, liability to the producer or shipper is implied in the case of spills or accidents during production, storage or transportation of any dangerous goods. The company shipping the dangerous good will either hire a contractor to deal with any problems, in which case they retain the liability, or obtain insurance. The latter alternative is the general course of action.

The insurance company acts as a regulatory body in that compliance to specified standards is required before insurance is issued. The whole company or system is thoroughly examined by the insurance company. Insurance premiums are dependent upon an environmental risk analysis which includes delivery of raw goods, system design, storage, shipment of goods, discharge regulations, compliance with safe handling procedures and previous history.

5.1.3 Hydrogen Storage

Hydrogen storage facility construction is indirectly regulated in that industry must ensure safe practice. The storage facility generally complies with NFPA (National Fire Protection Association) Standards No. 50-A, "Standards for Gaseous Hydrogen Systems at Consumer Sites" and 50-B, "Standards for Liquefied Hydrogen Systems at Consumer Sites". These standards in turn call for compliance to the ASME Boiler and Pressure Vessel Code and ANSI codes for piping, tubing and fittings. Preferred construction materials are indicated. For liquid hydrogen systems, containers are equipped with safety relief devices sized in accordance with CGA codes, Safety Relief Device Standards for Compressed Gas Storage Containers.

5.1.4 Worker Safety

Industry is responsible for providing a safe working environment. For federal undertakings, worker protection is dealt with by the Canadian Labour Code. Part 4 of this code, Canada Dangerous Substances Regulations, deals with the safety of the work environment. Factors such as isolation of dangerous goods, holding tanks, training of employees and combustible air-borne particles are included. Similar regulations are administered by the provinces. In Ontario, for example, worker protection is regulated by the Occupational Safety and Health Act, administered by the Ontario Ministry of Labour.

5.1.5 Vehicle Safety

Vehicle safety is regulated under the Motor Vehicle Safety Act, administered by Transport Canada. This Act stipulates performance standards for the fuel system which includes tank, fuel lines, and parts that control the injection of fuel into the engine.

For gasoline and diesel powered vehicles, crash testing is required. A limit on the amount of fuel that may leak out of the system is set. Performance under front, back and side collisions and tumbling is monitored.

Design standards for propane and CNG fuelled vehicles have been developed by the Canadian Gas Association and are enforced by provincial governments. Standards 149.2 - M80 and B 149.1 - M80 deal respectively with propane and CNG fuel systems.

No design standards have been developed for hydrogen vehicles as yet. It is expected that if a hydrogen fuelled vehicle can pass the same crash test used for gasoline, natural gas and propane vehicles, it will be considered safe. Further development is required in this area.

5.2 CODES AND REGULATIONS - U.S.

Equipment specifications for the transportation of hydrogen are strictly regulated by the Department of Transportation. Standards that may be adopted by U.S. regulatory bodies are those issued by the American Society of Mechanical Engineers, the American National Standards Institute, the Compressed Gas Association, the Instrument Society of America, the National Fire Protection Association and Underwriters Laboratories.

Hydrogen storage and safety standards are not regulated. Compliance with such standards is indirectly implied in that industry is responsible for worker safety and is liable for damages in case of an accident.

5.2.1 Transportation

Equipment specification, shipping and carrier regulations for gaseous and liquid hydrogen are designated in Title 49 of the Code of Federal Regulations sections 170 to 179. A summary of these regulations is presented in Table 5.1.

Interstate transportation of hydrogen is administered by various branches of the Department of Transportation. Transportation by

TABLE 5.1

REGULATIONS FOR DISTRIBUTION OF HYDROGEN

Distribution of hydrogen by	Equipment specifications	Transportation regulations
Cylinders filled with liquid—by highway	49 CFR 178.57 [2]	49 CFR (172.200-172.542), Also Parts 173.316, 177, 177.823, 177.840, 177.859, 397 [2, 3]
Highway truck trailers filled with liquid	CGA*-341 and DoT approval prior to fabrication: 49 CFR 107.103 [2, 4]	Requires "exemption" by the Office of Hazardous Materials Operations of DoT: 49 CFR (172.200–172.542), also Parts 173.32, 173.33, 177, 177.823, 177.859, 397 [2, 3]
Railway tank cars filled with liquid	49 CFR 179, also Parts 179.400, 179.401 [2]	49 CFR (172.200–172.542). Also Parts 173.316, 174 [2]
Container filled with liquid—by air or waterway	—	Not allowed under current regulations (see 49 CFR 172.101) [2]. Shipment by tank barge has been allowed under special permit of the DoT. Future shipments, if permitted, will require an "exemption".
Liquid pipeline	ANSI B31.8, B31.3* B31.10* [5–7]	49 CFR (190–192), also Part 195 [2]
Cylinders filled with compressed gas—by highway or highway truck trailers filled with compressed gas	49 CFR 173.34, also Parts 178.36, 178.37 [2]	49 CFR (172.200–172.542), also Parts 173.301, 173.302, 177, 177.823, 177.840, 177.859, 397 [2, 3]
Railway tank cars filled with compressed gas	49 CFR 173.31, also Parts 179, 179.500 [2]	49 CFR (172.200–172.542), also parts 173.314, 174 [2]
Container filled with compressed gas—by air	49 CFR 173.34, also Parts 178.36, 178.37 [2]	DoT approved cylinders on cargo aircraft only, with a maximum charge of 300 lb (136 kg) of H_2 per container package: 49 CFR 172.101, also Parts (172.200–172.542), 173.301, 173.302, 173.306, 175; see also CAB No. 82 [2, 9]
Container filled with compressed gas—by waterway	49 CFR 173.31, also Parts 173.34, 178.36, 178.37, 179, 179.500 [2]	DoT approved cylinders on cargo vessels only; DoT approved highway vehicles on trailership, ferry or carfloat only; DoT approved tank cars on trainship, railroad-car ferry or carfloat only. 49 CFR 172.101, also Parts (172.200–172.542), 173.301, 173.302, 173.306, 173.314, 176, 176.63, 176.76 [2]
Gas pipeline	ANSI B31.8, B31.3*; B31.2* [5, 6, 8]	49 CFR (190–192) [2]

General industrial safety matters, including the production and handling of flammable compressed and liquefied gases, are regulated by OSHA PL 91-596 [10].

* Not mandatory but industrially accepted standards.

Source: Hord, J., "Hydrogen Safety: An Annotated Bibliography of Regulations, Standards and Guidelines", *International Journal of Hydrogen Energy*, Vol. 5, pp. 579-584, 1980.

highway is administered by the Federal Highway Branch, railway transportation by the Federal Railway Branch, marine transportation by the U.S. Coast Guard, and pipeline tranmission by the Pipeline Safety Operations Branch. All other matters related to hazards in vehicular transportation of hydrogen are regulated by the Office of Hazardous Materials Operations.

Transportation of liquid hydrogen and other cryogenic fluids is not presently authorized for cargo tanks by the Department of Transportation's hazardous materials regulations unless a special permit is issued. Specifications, including design and test requirements for the liquid containers, support systems, insulation, construction materials, safety devices, piping and valves as outlined in the Compressed Gas Association Pamphlet - 341, "Insulated Tank Truck Specifications for Cold Liquefied Gases", must be met before the permit is granted. Transportation of liquid hydrogen is not allowed by air or waterway. To date, a special exemption has only been granted to NASA for marine shipment of cryogenic liquid hydrogen.

Standard B 31.10 has been developed by the American National Standards Institute for cryogenic liquid piping. In developing the above standard, standard B 31.3 for pressure and petroleum refinery piping was used as a guideline.

5.2.2 Industrial Insurance Agencies

Industrial insurance agencies have had a positive influence on hydrogen safety. As in Canada, liability to the producer or shipper is implied in case of spills or accidents during production, storage or transportation of any dangerous goods.

To obtain insurance to cover this liability, compliance with specified standards, as published by standard writing bodies, is required by the insurance company.

5.2.3 Worker Safety

Safe working conditions are mandated by the Occupational Safety and Health Act administered by the U.S. Department of Labour. Regulations dealing with gaseous and liquid hydrogen are based primarily on the NFPA standards 50 A and 50 B.

5.2.4 Hydrogen Storage and Safety

Standards and guidelines for hydrogen storage and safety are available but not regulated. As in Canada, industry has taken the initiative in adopting safe standards and practices. Most standards are adopted because of an insurance incentive. For storage of hydrogen at consumer sties, compliance with carriers' guidelines or with NFPA Standards 50 A and 50 B are recommended. Storage vessels for gaseous hydrogen systems are designed, constructed and tested in accordance with appropriate requirements of ASME Boiler and Pressure Vessel, Section III - Unfired Pressure Vessels. Piping and tubing conform to the appropriate ANSI codes.

Several good hydrogen manuals dealing with safe handling and storage of gaseous and liquid hydrogen have been published (51, 55). These manuals include safety in system design, nature of hydrogen hazard, recommended operating procedures, emergency instructions and worker training and safety.

For cryogenic liquid hydrogen storage, containers as specified by NFPA Standard 50 B are designed, constructed and tested in accordance with appropriate requirements of the ASME Boiler and Pressure Vessel Code or applicable provisions of API Standard 620. Safety relief devices on these stationary liquefied hydrogen containers are sized in accordance with CGA Pamphlet S-1, Part 3, Safety Relief Device Standards for Compressed Gas Storage Containers.

5.3 RECOMMENDATIONS

The existing network of mandatory and non-mandatory codes is adequate for present hydrogen use. Proof of this is the excellent safety record to date. In the past, standards have been developed by industry and special interest groups as deemed necessary. Standards are set before any market penetration to ensure conformity and public safety. With the development of new hydrogen technologies and applications, standards regulating these technologies may be required.

A twofold increase in industrial hydrogen consumption is projected by the year 2025. Greater than twofold increases are expected for some industries. Present regulations are expected to be adequate for an industrial consumption increase of this magnitude.

The market penetration of hydrogen as a transportation fuel is projected as 1.5 percent of the total hydrogen consumption by year 2025. The technology for the use of hydrogen as a surface vehicle or aircraft fuel has not been fully developed. There are no regulations for this technology as of yet. Regulations for similar technologies using hydrocarbon fuels are available and can be used as guidelines.

Hydrogen is presently produced by methane steam reforming. In the near future, penetration of electrolytic hydrogen production is expected. This is a relatively new technology and few standards have been set to date.

As a technology is developed, the standard writing body having jurisdiction over a particular technology or energy use will have to develop adequate guidelines to ensure safety before market penetration can be realized. Regulations for hydrogen use in the transportation sector will have to be more stringent than industrial regulations if comparable safety standards to existing fuels are to be maintained. On an industrial site, hydrogen is used by trained personnel. In the transportation sector, operating conditions may be far from ideal and therefore more prone to accidental occurrences.

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